BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, Sub 1314
DOCKET NO. E-7, Sub 1289
DOCKET NO. E-2, Sub 1315
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DOCKET NO. E-2, Sub 1314 DOCKET NO. E-7, Sub 1289 In the Matter of: Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source Advantage Choice Program and Rider GSAC DOCKET NO. E-2, Sub 1315 DOCKET NO. E-7, Sub 1288 In the Matter of: Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Clean Energy Impact Program	**JOINT INITIAL COMMENTS OF SOUTHERN ALLIANCE FOR CLEAN ENERGY, NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, AND CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION**

PURSUANT TO the North Carolina Utilities Commission's (Commission) February 9, 2023 *Order Requesting Comments* filed in *In the Matter of: Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source Advantage Choice Program and Rider GSAC* (GSAC Proceeding), the February 9, 2023 *Order Requesting Comments* filed in *In the Matter of: Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Clean Energy Impact Program* (CEI Proceeding), March 28 *Order Granting Extension* filed in the GSAC Proceeding and March 28 *Order Granting Extension* filed in the CEI Proceeding, the Southern Alliance for Clean Energy (SACE), the North Carolina Sustainable Energy Association

(NCSEA), and the Carolinas Clean Energy Business Association (CCEBA) submit these Joint Initial Comments.

Session Law 2021-165 (House Bill 951 or H951) created a new opportunity for North Carolinians to access clean energy when it directed the North Carolina Utilities Commission to establish riders for voluntary programs that allow industrial, commercial, and residential customers to purchase renewable energy or renewable energy credits (voluntary customer programs). These voluntary customer programs must result in new, additional renewable energy resources coming online, above and beyond the baseline procurement required by law and regulation—renewables that are "surplus" to regulatory requirements. "Regulatory surplus" is essential; it is what customers expect; and it is required by H951.

Duke Energy has proposed two programs Green Source Advantage Choice (GSAC) and Clean Energy Impact (CEI), and is likely to propose a third program that was discussed with stakeholders, possibly to be named Clean Energy Connection (CEC). Unfortunately, none of Duke's proposals achieve regulatory surplus, instead either allocating participating customers a share of the zero-carbon resources that will be procured to meet the carbon-reduction requirements established by H951 (Carbon Plan resources) or reducing those procurements. The Commission should not approve programs that do not achieve regulatory surplus.

There are ways to design voluntary customer programs that would achieve regulatory surplus. We propose multiple potential options in this letter. We recommend directing Duke to work with stakeholders to refine the potential programs discussed in this letter, which achieve regulatory surplus; work with stakeholders to refine the full collection of potential programs; and then to deploy those the Commission approves. It might be appropriate to pilot some programs using the forthcoming "rapid prototyping" process that Duke is developing for non-EE/DSM customer programs.

1. "Regulatory Surplus" is Essential to Customer Renewable Programs

H951 will require procurement of a large quantity of zero-carbon resources to meet the carbon-reduction requirements for the power sector for 2030 and 2050 set forth in Section 1 of the law (Carbon Plan). In order to comply with the Carbon Plan, this level of procurement must occur. Accordingly, the Carbon Plan establishes a baseline level of procurement of new zero-carbon resources between now and the Carbon Plan deadlines (Carbon Plan baseline procurement).

Customers who voluntarily elect to purchase renewable energy to reduce the emissions associated with their electricity use do so with the understanding that they purchase something above and beyond what would otherwise have been delivered to all customers of that electric public utility.

The essential feature of the voluntary customer programs established under H951 is that participation results in procurement of additional zero-carbon resources that would not have been procured otherwise. Therefore, new renewable resources will need to be procured above and beyond the Carbon Plan baseline procurement in order to supply the program capacity. The question whether renewable resources are truly additional to business as usual is sometimes referred to as additionality, although the term "regulatory surplus"--meaning the renewable energy procured is "surplus" to regulatory requirements--is more accurate in this context.

Just as renewable energy credits (RECs) that have been retired on a customer's behalf may not be used for compliance with the Renewable Energy/Energy Efficiency Portfolio Standard, the carbon emission reduction attributes associated with customers' participation in voluntary programs must be retired on behalf of the participating customers and only on their behalf, without being counted towards the Carbon Plan baseline procurement trajectory.

As part of its Clean Energy Impact (CEI) program, Duke Energy proposes to retire carbon emission reduction attributes and RECs (together, Clean Energy Environmental Attributes or CEEAs) on behalf of participating customers and provide customers with documentation of the retired carbon emission reduction attributes.[1] As part of its Green Source Advantage Choice (GSA Choice) program, Duke Energy will again retire the RECs and the carbon emission reduction attributes on behalf of participating customers.[2] For both of these voluntary customer programs, Duke Energy specifies that program capacity will be sourced from Carbon Plan resources, which are already required for compliance with the Carbon Plan.[3] The size of future Carbon Plan baseline procurements will be reduced commensurate with the size of any renewable resources procured under a three-party agreement with a participating GSA Choice customer, renewable developer, and Duke Energy.[4] Thus, Duke Energy's GSA Choice program and CEI

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[1] *Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Requesting Approval of Clean Energy Impact Program*, p. 6-7, Docket Nos. E-2, Sub 1315 and E-7, Sub 1288 (North Carolina Utilities Commission January 27, 2023) (NC Clean Energy Impact Application).

[2] *Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source*
Advantage Choice Program and Rider GSAC, Appendices B and C, Docket Nos. E-2, Sub 1314 and E-7, Sub 1289 (North Carolina Utilities Commission January 27, 2023) (NC GSA Choice Application).

[3] *Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source*
Advantage Choice Program and Rider GSAC, p. 5-6, Docket Nos. E-2, Sub 1314 and E-7, Sub 128 (North Carolina Utilities Commission January 27, 2023) (NC GSA Choice Application); *Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Requesting Approval of Clean Energy Impact Program*, f.n. 5, Docket Nos. E-2, Sub 1315 and E-7, Sub 1288 (North Carolina Utilities Commission January 27, 2023) (NC Clean Energy Impact Application).

[4] *Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source*
Advantage Choice Program and Rider GSAC, p. 5-6, Docket Nos. E-2, Sub 1314 and E-7, Sub 128 (North Carolina Utilities Commission January 27, 2023)(NC GSA Choice Application).

program would retire, on behalf of participating customers, RECs and environmental attributes from Carbon Plan baseline procurement resources.[5] This means that participating customers that invest in CEEAs associated with the Carbon Plan resources Duke Energy is required to procure will not, in actuality, have contributed to any emission reductions.

2. Customers Want and Expect Programs to Be Surplus to Regulatory Requirements

Customers want and expect regulatory surplus. In 2020, voluntary buyers procured about 35% of all non-hydro renewable energy generated in the United States.[6] This voluntary market leverages private investment to reduce the environmental and health impacts of electricity generation.

North Carolina should protect the ability of voluntary actors to reduce emissions in order to support and enhance, rather than undercut, voluntary renewable energy (VRE) markets and motivate more businesses to invest in clean energy with their private funds. Preserving the avoided carbon-emission value of VRE produces incremental emissions reductions driven by private sector investment. In other words, it ensures that H951 does not become a *ceiling* for carbon-emission reductions.

North Carolina's actions could have knock-on effects in other regions as well. If North Carolina adopts voluntary customer programs that are *not* surplus to regulatory requirements then buyers who want to ensure that their purchases of voluntary renewable energy *are* surplus to regulatory requirements will likely react in one of a few ways. They might purchase renewable energy from outside of the state or region, supporting economic investments in *other* states or regions. They might simply decline to purchase VRE entirely, for example, if they are motivated to purchase only local or in-state renewable energy. And they might avoid or leave North Carolina in favor of jurisdictions allowing regulatory surplus. For example, Meta, the largest commercial or industrial purchaser of solar power in the United States, applies an "emissions first" rationale into its data-center siting process, aiming for local sourcing wherever feasible.[7]

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[5] Duke Petition for Approval of Green Source Advantage Choice Program at 6 n.2, *In the Matter of: Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source Advantage Choice Program and Rider GSAC*, Docket Nos. E-7 Sub 1289 and E-2, Sub 1314 (N.C.U.C. Jan. 27, 2023).

[6] NREL. Status and Trends in the Voluntary Market (2020 data) available at: https://www.nrel.gov/docs/fy22osti/81141.pdf

[7] John Fitzgerald Weaver & Michael Schoeck, *Meta picks utilities based on solar potential at data centers*, PV Mag., March 23, 2023, https://pv-magazine-usa.com/2023/03/23/meta-picks-utilities-based-on-solar-potential-at-data-centers/.

Supporting "new" projects is one of the six "Buyers' Principles" adopted by the Clean Energy Buyers Association (CEBA),[8] a membership association for energy customers seeking to procure clean energy across the U.S that aspires to achieve a 90% carbon-free U.S. electricity system by 2030 and to cultivate a global community of energy customers driving clean energy.[9] While "new" is not always synonymous with "additional" or "regulatory surplus," large customers want their actions to meaningfully contribute to grid decarbonization, as CEBA's sister research organization's recent work suggests.

The Clean Energy Buyers Institute (CEBI) is a 501(c)(3) nonprofit organization that was created alongside CEBA to provide research and analysis for the renewable energy industry and customers.[10] CEBI convened over 100 energy customers and other stakeholders for a series of 10 workshops in late 2022 for CEBI's Next Generation Carbon-Free Procurement Initiative.[11] The current VRE market requires customers to verify their procurement through "energy attribute certificate (EAC) ownership" to prevent multiple parties from counting or claiming the same attributes, which oversaturates the market for renewable energy and allows polluting resources to remain online for longer.[12]

The outcome of this initiative was a guide for energy procurement and management.[13] The first step in the process outlined in the guide is to "Evaluate whether an activity will lead to indirect emission reductions *that otherwise wouldn't have happened*."[14] The guide explains that "even when a decision causes new indirect emissions reductions, one should consider whether *these emissions reductions might have happened anyway*, whether or not the decision-maker spends their resources."[15] It also recommends against renewable energy certificate (REC) arbitrage because if the "compliance-grade" RECs that the customer sells are "now used to help meet compliance with the RPS targets, this

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[8] *Buyers' Principles*, Clean Energy Buyers Association, https://cebuyers.org/programs/education-engagement/buyers-principles/ (last visited Nov. 16, 2022) ("Access to new projects that reduce emissions including bundled clean energy products, like energy and Renewable Energy Credits (RECs); the ability to prevent double-counting within the energy consumer community; and sourcing projects near operations and/or closest regional energy grids.").
[9] *Our Vision*, Clean Energy Buyers Association, https://cebuyers.org/about/vision/ (last visited Mar. 26, 2023).
[10] *About*, Clean Energy Buyers Institute, https://cebi.org/about/ (last visited Mar. 26, 2023).
[11] Doug Miller, CEBI, The Next Generation Carbon-Free Electricity Procurement Activation Guide at 5 (2022), https://cebi.org/wp-content/uploads/2022/10/Community-Guide_Oct31st_v1.pdf.
[12] *Id.* at 9.
[13] Attachment 1, Gregory Miller, CEBI, Applying The Consequential Emissions Framework For Emissions-Optimized Decision-Making For Energy Procurement and Management at 4 (2023), https://cebi.org/wp-content/uploads/2022/11/Applying-The-Consequential-Emissions-Framework-For-Emissions-Optimized-Decision-Making-For-Energy-Procurement-And-Management.pdf (noting that the "guide builds off of the learnings from CEBI's Next Generation Carbon-Free Electricity Procurement Activation Guide, which shares the market evolvements needed to enable a broader suite of next-generation procurement options, such as procurement that maximizes the location- and time-based decarbonization potential of CFE procurement").
[14] *Id.* at 8 (emphasis added).
[15] *Id.* (emphasis added).

reduces the amount of clean energy that the local utility would have otherwise been mandated to procure."[16] In a hypothetical example, the guide explains that a customer's energy manger would consider the interactions between the project and any regulatory requirements in the region, such as a cap-and-trade program or renewable portfolio standard.[17] The CEBI guide notes that there is not yet an agreed-upon standard for applying the customer decision-making framework it outlines, but customers' focus on driving grid decarbonization beyond business as usual seems clear.

Regulatory surplus is also a requirement of the Center for Resource Solutions' (CRS)[18]' Green-e® Energy Program. For over 20 years, Green-e ® has been the leading independent certification for voluntary renewable electricity products in North America, and in 2021 certified retail sales of over 110 million megawatt-hours (MWh), serving over 1.3 million retail purchasers of Green-e ® certified renewable energy, including over 309,000 businesses. As evidenced in CRS' Nov 14, 2022 comments to the North Carolina Utilities Commission,[19] Duke's proposed customer programs threaten to diminish the impact of corporate and other voluntary green power procurement strategies that can offer additional greenhouse gas (GHG) benefits on top of regulations if the right policy and accounting mechanisms are in place. Regulatory surplus is key to ensuring that GHG regulations in the power sector protect voluntary demand and private investment in renewable energy.[20]

Accordingly, if Duke Energy were to offer voluntary customer programs that did *not* generate additional new renewable energy resources it very likely would cause customer confusion and dissatisfaction and, once the issue was understood, non-participation. The discussion above indicates this will be true for sophisticated large customers such as commercial and industrial customers. The problem is even more concerning for small customers including residential customers, who will be able to participate in the proposed Clean Energy Impact (CEI) program[21] and the CEC or similar "shared solar" program, if filed. Residential customers will need to be informed that the money they contributed to participating in a voluntary renewable program did not in fact result in procurement of any additional

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[16] *Id.* at 9.
[17] *Id.* at 22.
[18] CRS is a 501(c)(3) nonprofit organization that creates policy and market solutions to advance sustainable energy. CRS provides technical guidance to policymakers and regulators at different levels on renewable energy policy design, accounting, tracking and verification, market interactions, and consumer protection. CRS also administers the Green-e ® programs. More info available at: https://resource-solutions.org/g2022/.
[19] CRS (November 14th, 2022). Comments in NC in response to the Verified Petition for Approval of Carbon Plan filed in docket No. E-100, Sub 179 on behalf of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC Available at: https://resource-solutions.org/document/111422/
[20] CRS (2018). Impactful Corporate Renewable Energy Procurement in States With Carbon Policies Available at: https://resource-solutions.org/wp-content/uploads/2018/09/Corporate-Renewable-Energy-Procurement-Corporates.pdf
[21] Duke CEI Application 6, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=2df049fd-9cae-4601-adb8-3cc83074009f.

renewable energy, but only subsidized the Carbon Plan baseline procurement that would have occurred anyway. This is particularly true if customers are presented with a personal emissions calculation tool, as described below.

To implement HB 951 equitably, the Carbon Plan should avoid shifting both costs and emissions to other residential customers. If HB 951 is implemented in a way that allows for voluntary purchases to be counted towards Caron Plan compliance, this potentially reduces the benefits of compliance to other residential customers by allowing Duke to achieve compliance, at least in part, by delivering renewable energy exclusively to voluntary buyers. On the other hand, not counting the benefits of VRE toward compliance will require additional reductions from activities that benefit non-VRE Duke customers.

Yet as proposed, that is what will happen. Duke Energy will provide customers who participate in GSAC and CEI—and CEC, if filed-- documentation of the carbon emission reduction attributes retired on their behalf, but the attributes will have been sourced from Carbon Plan baseline procurement.

3. H951 Requires Customer Programs' Capacity Be Surplus to Regulatory Requirements

The text of H951 anticipated that voluntary customer programs would be surplus to regulatory requirements in a few ways. Section 5 of the law provides:

> The Utilities Commission shall also . . . (iv) establish a rider for a voluntary program that will allow industrial, commercial, and residential customers who elect to purchase from the electric public utility renewable energy or renewable energy credits, including in any program in which the identified resources are owned by the utility in accordance with sub-subdivision b. of subdivision (2) of Section 1 of this act, **to offset their energy consumption**, which shall ensure that customers who voluntarily elect to purchase renewable energy or renewable energy credits through such programs bear the full direct and indirect cost of those purchases, **and that customers that do not participate in such arrangements are held harmless, and neither advantaged nor disadvantaged**, from the impacts of the renewable energy procured on behalf of the program customer, **and no cross-subsidization occurs**.

Session Law 2021-165, Section 5 (emphasis added).[22] The statute requires that renewable energy capacity procured for voluntary customer programs be surplus to regulatory requirements in at least three ways.

First, if the resources procured under the voluntary customer programs are not surplus then participants will not be "offsetting" their energy consumption in any meaningful sense because they will not be causing any reduction in emissions.

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[22] https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf

Rather, they will merely be reducing the cost of procuring system resources that would have been procured anyway pursuant to existing regulatory requirements.

Second, since the cost of resources on Duke Energy's system is borne by all customers, cross-subsidization is prohibited in both directions - non-participants should be "neither advantaged nor disadvantaged" by the programs. System-wide costs, including compliance with Carbon Plan requirements, should be shared by all customers. Customer programs, in contrast, are required under the law to internalize the costs of renewable resources. Cross-subsidization is explicitly prohibited by Section 5, three different times ("held harmless," "neither advantaged nor disadvantaged," and "no cross-subsidization"). Despite prohibitions in the law, in stakeholder meetings Duke Energy representatives have promoted cross-subsidization as a key benefit of the programs as proposed.[23]

The emissions calculation tool that Duke has discussed in stakeholder meetings further illustrates the problem. As described by Duke representatives, the proposed tool would attempt to show a participating customer the emissions associated with their electricity consumption. It would essentially take the customer's electricity use for a given period, subtract the amount of electricity associated with the customer's participation in a customer renewables program, and multiply the remaining electricity use by the system average emissions rate. This calculation makes sense for regulatory-surplus renewables that would *not* have been procured as a system resource without customer investment; the customer's voluntary participation caused the emissions reduction associated with those renewables and should be credited to the customer in a carbon accounting.

The problem with this approach is that when the customer program simply claims a portion of the renewable energy that would have been procured anyway under existing regulatory requirements, the participating customer has not actually reduced emissions at all. Duke Energy should not be permitted to sell customers participation in such a program. Furthermore, this approach artificially attributes more emissions to non-participating customers than they cause. Having sold the emissions reductions associated with some renewable system resources to participating customers, Duke will have artificially reduced their share of system-wide emissions and must balance the equation by artificially attributing additional emissions to non-participating customers, for example by multiplying their energy usage by a higher system average emissions rate.[24]

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[23] *See* Attachment 2, Aug. 4 presentation, slide 5 ("Money received will help 'buy down' the cost of our projects/benefits all customers"). Further support was given orally. As discussed further below, the *direction* of the cross-subsidization is not necessarily from participating customers to non-participating customers as Duke seems to believe.

[24] E.g., if the actual emissions rate is measured in tons of $CO2$ per MWh, Duke would subtract the zero-carbon MWh purchased by customers through the customer programs from the denominator, while the actual emissions in the numerator would stay the same, resulting in a higher emissions rate.

Duke's proposed emissions calculation tool also highlights how non-participating customers are not held harmless. The renewable energy facilities associated with the customer programs would be Carbon Plan resources, with program capacity sourced from a portion of the renewable resources that Duke procures through the annual renewable procurement process.[25] Selling credits for a portion of this procurement to customers through the voluntary customer programs effectively sells claims to renewable energy at artificially reduced cost, subsidized by non-participants, because the renewable resources in question will have to be procured regardless. And offering that subsidized access to renewable energy *claims* disadvantages non-participating customers by denying them that same claim. Furthermore, it deprives all customers of the additional, regulatory-surplus new renewable energy that at least some of the participating customers would have procured if the program were additional, along with the emissions, economic, and resilience benefits that it would have brought.

Third, if the General Assembly meant for resources used for voluntary customer programs to be drawn from those procured under the Carbon Plan then it would not have been necessary to specify in Section 1(2)b. that the ownership split described therein which, applies to solar generation selected by the [Commission] pursuant to the Carbon Plan, should also apply to solar procured through any voluntary customer programs, since procurement for those programs would already be pursuant to Section 1.[26]

As a related point, Duke Energy has proposed similar programs in South Carolina[27] and resources procured for these South Carolina programs will serve Duke Energy's systems across both states.[28] If Duke Energy proposed to use zero-carbon resources procured for these South Carolina programs to meet its Carbon Plan carbon-reduction requirements, then Duke Energy should not be permitted to retire CEEAs on behalf of participating customers and sell participation in a program that is not additional.

4. Federal Requirements Regarding Regulatory Surplus

Multiple federal bodies require accurate reporting of renewable energy claims and programs that result in renewable energy resources that are not additional to regulatory requirements will implicate their requirements. The Federal Trade Commission (FTC) has guidelines for environmental marketing claims,

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[25] See GSAC petition at 5.
[26] Session Law 2021-165, Section 1(2)b., https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf ("These ownership requirements shall be applicable to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program.").
[27] Joint Application Of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Modifications to Green Source Advantage Programs, Docket No. 2018-320-E (Public Service Commission of S.C. Oct. 5, 2022), https://dms.psc.sc.gov/Attachments/Matter/5121ac33-0bd8-4265-97c3-f8ed68656ee0 (SC GSA Application); SC Renewable Choice and Clean Energy Impact Application.
[28] *See* SC Renewable Choice and Clean Energy Impact Application at 10.

which specifically state "[i]f a marketer generates renewable electricity but sells renewable energy certificates for all of that electricity, it would be deceptive for the marketer to represent, directly or by implication, that it uses renewable energy." 16 CFR § 260.15(d). The FTC has sent at least one enforcement letter to a utility in response to claims that the utility made to its customers that the customers purchase renewable energy when in fact the utility sold the RECs generated by its renewable facilities to out-of-state buyers. If Duke's customers were to rely on the proposed non-regulatory-surplus customer programs to claim that they were using renewable energy when in fact their participation in those customer programs does not result in any additional renewable energy production above and beyond amount Duke would have produced without the purchase, then those customers' claims about using renewable energy would seem to be similarly deceptive and prohibited by FTC regulations.

Similarly, the Securities Exchange Commission (SEC) has developed a proposed rule requiring registrants to provide certain climate-related information in their registration statements and annual reports.[29] The proposed rule would require registrants to disclose Scope 1 emissions, meaning emissions directly from the registrant's own operations; Scope 2 emissions, meaning indirect GHG emissions from the generation of purchased or acquired electricity, steam, heat, or cooling; and Scope 3 emissions, meaning all other indirect emissions upstream and downstream activities of a registrant's value chain, if those emissions are material or the registrant has set a GHG emissions reduction target or goal that includes its Scope 3 emissions.[30] The SEC's proposed rule refers to EPA guidance on Scope 2 emissions,[31] and the EPA recommends that RECs be surplus to regulatory requirements.[32]

Finally the federal government's own procurement must be surplus to regulatory requirements. Federal agencies must pursue 100% clean energy by 2030:

> Transitioning to 100 Percent Carbon Pollution-Free Electricity. Each agency shall increase its percentage use of carbon pollution-free electricity, so that it constitutes 100 percent of facility electrical energy use on an annual basis, and seek to match use on an hourly basis to achieve 50 percent 24/7 carbon pollution-free electricity, by fiscal year 2030. In addition, agencies shall facilitate new carbon pollution-free electricity generation and energy storage capacity by authorizing use of their real property assets, such as rooftops, parking structures, and adjoining land, for the development of new carbon pollution-free electricity generation and

[29] SEC, The Enhancement and Standardization of Climate-Related Disclosures for Investors, RIN 3235-AM87, https://www.sec.gov/rules/proposed/2022/33-11042.pdf.
[30] *Id.* at 150-51.
[31] *Id.* at 160, 160 n.439.
[32] EPA, Greenhouse Gas Inventory Guidance: Indirect Emissions from Purchased Electricity at 12-13 (2020), https://www.epa.gov/sites/default/files/2020-12/documents/electricityemissions.pdf.

energy storage through leases, grants, permits, or other mechanisms, to the extent permitted by law.

Executive Order No. 14057, Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, Sec. 203 (December 8, 2021), https://www.govinfo.gov/content/pkg/FR-2021-12-13/pdf/2021-27114.pdf.

The White House Council on Environmental Quality (CEQ) guidance for Executive Order No. 14057 explains how to calculate carbon-free electricity (CFE) and the guidance makes clear that agencies must count "grid-supplied CFE."[33] To calculate the percentage of CFE that it uses, a federal agency must add together 1) purchased CFE, 2) on-site CFE, 3) purchased energy attribute certificates (EACs), and 4) grid-supplied CFE.[34] Grid-supplied CFE is CFE that is delivered "as part of default electricity service or the electricity grid mix from a utility or electric service provider."[35] When CFE purchased through a voluntary customer program is not surplus to regulatory requirements, that CFE constitutes "grid-supplied CFE" even if a customer paid a premium for it through a voluntary customer program, because the same amount of CFE would have been provided through the utility's default service—supplied by the grid--regardless of the customer's purchase. Accordingly, any federal facilities in the state should be expected to count electricity supplied through the voluntary customer programs as proposed, as "grid-supplied CFE," making it ineligible to be counted again as "purchased" for the purpose of meeting the net annual CFE goal. As a result, it would not make sense for federal facilities to participate in the programs.

Duke's voluntary customer programs in North Carolina should facilitate compliance with current and forthcoming federal requirements by procuring renewable energy that is surplus to H951's requirements, making it more appealing to large customers to remain in and move to the state.

5. Emissions Counting is Straightforward

The way to ensure regulatory surplus is simple: do not count the emissions reductions associated with renewable energy procured for customer programs towards compliance with the Carbon Plan. The Center for Resource Solutions (CRS) recommended this solution in its comments on Duke's proposed Carbon Plan.[36] Duke would simply calculate the emissions avoided by generating resources procured through the voluntary customer programs and subtract that quantity from its annual emissions reductions. For example, if the total reductions to achieve the 70% reduction target in 2030 were 100 tons and 10 tons of those

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[33] CEQ, Implementing Instructions for Executive Order 14057 Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability at 10-11 (2022), https://www.sustainability.gov/pdfs/EO_14057_Implementing_Instructions.pdf.
[34] *Id.* at 11.
[35] *Id.*
[36] Lucas Grimes, CRS Comments on Duke Carbon Plan (Nov. 14, 2022), https://resource-solutions.org/document/111422/.

were avoided by voluntary renewable energy generation, Duke should reduce an additional 10 tons, i.e. reduce 110 tons.

During the stakeholder process, Duke argued that the language of H951 established a “mass cap” on emissions from Duke’s generating facilities in the state. Duke representatives appeared to believe the statute requires measuring compliance by simply counting the “stack” emissions of all generating facilities owned or operated by Duke, which thereby counts the emissions reductions associated with facilities procured through voluntary customer programs.

This is wrong for three reasons. First, the Carbon Plan requires a minimum level of emissions reductions, not a maximum.[37] If there could be any doubt whether the 2030 carbon-reduction requirement is a minimum, it would be resolved by inclusion of the subsequent 2050 carbon-reduction requirement of net zero.

Second, in statutory construction a section dealing with a specific situation controls in that situation over other sections of general application.[38] The specific provisions in Section 5 of H951 that require customer programs to procure new additional resources, described above, must be given effect within the general requirement to reduce stack emissions at least 70% below 2005 levels by 2030.

Finally, Duke’s proposed approach simply smacks of double-counting. For a given renewable project participating in the customer programs, the customer would be counting its emissions reductions towards the customer’s emissions-reduction goals or otherwise claiming the retirement of carbon emission reduction attributes, while at the same time Duke would be counting the same emissions reductions towards compliance with the Carbon Plan. This results in the same reduction being counted on two ledgers, both the customer’s and Duke’s.

During the stakeholder process, Duke also raised a concern that it becomes increasingly difficult to establish that projects are surplus to regulatory requirements over time, as we approach the 2050 requirement of net-zero emissions. There is some truth to this and eventually it could become valuable to measure regulatory surplus in annual increments, declining over time as Duke’s required emissions reductions brought its annual emissions near zero. But we have a long way to go before that happens. In addition, it is possible that Duke will fail to meet its regulatory requirements on time, further delaying when this concern might materialize. For example, as a result of the future interconnection constraints that Duke expects, it is procuring low volumes of renewable resources relative to the trajectory it will need to meet the 2030 requirement, potentially challenging compliance.

[37] G.S. § 62-110.9.

[38] *Westminster Homes, Inc. v. Town of Cary Zoning Bd. of Adjustment*, 354 N.C. 298, 304, 554 S.E.2d 634, 638 (2001).

6. Concerns About Future Interconnection Capacity Must Not Stand in the Way of Developing Successful Customer Programs

During the stakeholder process, Duke stated that it would not be possible for its customer renewable programs to result in regulatory-surplus renewable energy facilities because the Carbon Plan resources will already exhaust Duke's maximum annual interconnection capacity through 2030. In other words, there will be no room to interconnect additional new renewable energy facilities beyond the Carbon Plan requirements. Duke's concerns about future interconnection capacity must not stand in the way of successful customer programs.

First, the theoretical limit on interconnections in future years is not static but depends on actions taken in the intervening years—and can be increased. Duke's Carbon Plan filings show the effectiveness that forthcoming improvements will have. Duke modeled two solar interconnection scenarios, one premised on meeting the Carbon Plan carbon-reduction requirement for 2030 in 2034, and one premised on meeting it in 2030.[39] In both cases, Duke estimated that a maximum of 750MW of solar could be interconnected in 2027, increasing to 1,350MW or even 1,800MW per year by 2030 as a result of "process improvements and transmission expansion plan upgrades," along with additional transmission expansion planning studies and associated upgrades to enable the 1,800MW scenario.[40] It is more important to meet the 2030 emission-reduction requirement than to risk procuring renewable resources in the near term that ultimately are not all interconnected in the same future year, and doing so can help to identify the bottlenecks and chokepoints in existing systems and processes sooner, while there is time to develop solutions and still meet the 2030 requirement on time.[41]

Furthermore, Duke's estimate for future years appears too low. The "Red Zone Transmission Expansion Plan" (RZEP) projects will come online beginning in 2024, with half online by mid-2026.[42] The forecasted maximum of 750MW in 2026, based on historical interconnections, does not take this major development into account. Furthermore, the four-year gap between procurement and

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[39] Duke Proposed Carbon Plan, App'x I at 6, Table I-2, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=0f3bac67-2d25-4480-beaf-12c93804691b.

[40] *Id.* at 6.

[41] *See* Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement Volume for the 2022 Solar Procurement, *In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Joint Petition for Approval of Competitive Procurement of Renewable Energy Program*, and *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c)*, Docket Nos. E-2, Sub 1159; E-2, Sub 1297; E-7, Sub 1156; E-7, Sub 1268 at 16-17 (N.C.U.C. Nov. 1, 2022) (Comm'rs Clodfelter and Hughes, dissenting in part), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=491aff9d-40ff-4af4-8ce2-16e3c74e3778.

[42] CPSA Modeling Panel Direct Cross Exhibit 1, *In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan*, Docket No. E-100, Sub 179 (N.C.U.C. Sept. 20, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=918e3200-1e5e-45e7-9abb-c085b60b1b40 (providing projected completion dates for RZEP projects)

commercial operation is an estimate, not a law; solar procured in 2022 could come online sooner or later than 2026.[43]

Transparency about interconnection capacity will be essential to overcoming any future interconnection capacity limitations and developing successful customer programs that procure regulatory-surplus renewable energy facilities. Developers will need accurate, granular, and up-to-date information about the interconnection capacity across Duke's system, both at the transmission and distribution levels. At the distribution level, the effort should begin with the hosting capacity analysis that Duke has begun preparing for a small portion of its territory, but this will need to be expanded to cover the entire state and meet the basic criteria above.

7. Proposals

There are multiple ways to achieve regulatory surplus, although they may require initiative and creativity. Five potential options follow.

a. Proactively Address Interconnection Challenges

The first and foremost is simply to procure projects surplus to regulatory requirements--calculated as described above--and proactively address potential future interconnection challenges rather than allowing fears about those challenges to stand in the way of successful customer programs. Duke Energy will require any third-party GSA Facilities to submit an interconnection request into the Definitive Interconnection System Impact Study process. Any other GSA Choice program capacity will be sourced from Duke Energy's annual solar procurements, which will utilize a Resource Solicitation Cluster in 2023 and 2024.This process will allow Duke Energy the time and information necessary to assess its ability to interconnect additional, new renewable resources through customer programs, despite its forecasted inability to do so.

b. Use Revised Large-generator Interconnection Procedures

Another possibility is to make use of Duke's newly revised large-generator interconnection procedures (LGIP)[44] to fast-track new zero-carbon replacement

[43] Regardless of the actual practical limit on interconnections in a given year, it would be inappropriate to for interconnection limits to reduce the amount of solar to be procured under the Carbon Plan in order to meet the 2030 carbon-reduction requirement, which must be determined by the least-cost path to meeting that requirement. If that amount were reduced in order to make room to interconnect solar associated with voluntary customer programs then those programs again would not be generating "surplus" or "additional" new renewable resources above and beyond the status quo.

[44] Duke Energy Florida, LLC submits tariff filing per 35.13(a)(2)(iii: Revisions to Attachments J and K to Joint OATT to be effective 8/1/2022 under ER22-2007, (June 1, 2022), FERC Accession No. 20220601-5225, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220601-5225&optimized=false; *see also* Docket No. E-100, Sub 179, Tr. Vol. 16 at 207:23-218:2 (Witness Roberts confirming that revised LGIP allows replacement generation using a different fuel type or combination of fuels, including standalone storage).

generation at the sites of fossil generators that have retired or will be retired soon--perhaps facilitated by the replacement generation enabled by the customer programs—while taking advantage of funding and tax credits available through the Inflation Reduction Act (IRA). After the IRA, including the tax credit bonuses available for new solar projects located near retired coal-burning generators, the all-in cost of local replacement renewable energy projects is cheaper than the cost to operate 97% of existing coal generation, including all of the coal plants in North Carolina.[45] Furthermore, recent analysis indicates that if solar-plus-storage facilities had replaced North Carolina's remaining coal generation units "it could have eliminated or at least significantly reduced the utility's capacity shortfalls, preventing or shortening the service interruptions" experience during Winter Storm Elliott.[46]

Duke's revised LGIP allows "an owner of a retiring generating facility to submit a generation replacement request to replace the retiring facility with a new facility requiring equal or less interconnection service and have that request be expeditiously processed and studied *outside* of the interconnection study process if certain criteria are met."[47] Duke does not appear to be anticipating making this opportunity—LGIP fast-track interconnection at existing sites—available as part of its ongoing and future Carbon Plan-derived solar procurements,[48] nor using it to accelerate coal retirements, meaning this proposal would allow interconnection of regulatory-surplus clean energy.

Many types and combinations of new zero-carbon resources, including storage, brought online through customer programs could meet these criteria and

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[45] Michelle Solomon, et al., Energy Innovation, Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment p.17 (2023), https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf (click the link at the word "spreadsheet" for details).

[46] Dennis Wamsted, Inst. for Energy Economics and Financial Analysis, Fossil Fuels Fail Reliability Test: Forced Outages During a December Freeze Underscore Serious Performance Problems Facing Coal- and Gas-Fired Electric Generators at 19 (2023), https://ieefa.org/resources/fossil-fuels-fail-reliability-test.

[47] Order Accepting Tariff Revisions, *Duke Energy Carolinas, LLC, Duke Energy Progress LLC, & Duke Energy Fla., LLC Duke Energy Progress, LLC Duke Energy Carolinas, LLC*, 180 FERC ¶ 61,156, P 7 (Sept. 6, 2022). Those criteria are the following: (1) the owner submits a replacement request at least one year prior to the retirement (with an exception for forced outages); (2) the replacement resource is located at the same electrical point of interconnection; (3) the replacement generation is commercial within three years of the retirement of the original generating facility or within four years after a forced outage; (4) the replacement generation request is made at least 12 months after (a) any assignment of the LGIA applicable to the existing generating facility, and (b) the date of any sale or other transfer of the existing generating facility; and (5) the replacement of the retiring resource would not have a material adverse impact on the transmission system. *Id.*

[48] *See* Motion to Open New 2023-2024 Solar Procurement Program Dockets, Grant Flexibility to Administer Future Solar RFPs Through Resource Solicitation Clusters, and for Extension of Time to Allow Further Stakeholder Engagement, Attachment 1 at 18, Docket No. E-100, Sub 179 (N.C.U.C. Jan. 27, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=0c889eb3-0e65-4786-94d0-9171dc184aee (outlining forthcoming RFP).

interconnect quickly. For example, solar-plus-storage could allow a coal plant to retire early, as happened recently in Nevada, where the North Valmy coal plant will be replaced by two solar-plus-storage facilities built in Valmy, NV.[49]

Replacement generation need not be precisely on-site to qualify for the LGIP fast-track, so long as it uses the same point of interconnection and does not have a material adverse impact on the transmission system.[50] Any new transmission or upgrades necessary to connect the new zero-carbon replacement generation with the grid at the existing point of interconnection could be funded through the IRA's Energy Infrastructure Reinvestment (EIR) Program (Section 1706) administered by the U.S. Department of Energy's Loan Programs Office (LPO).[51] Under the EIR Program, LPO is making available up to $250 billion in loan guarantees for projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations, such as repurposing shuttered fossil energy facilities for clean energy production, and could include transmission interconnection to off-site clean energy.[52] This excellent opportunity to save North Carolina customers money on necessary infrastructure expires September 30, 2026.

A customer program built around replacement generation using the LGIP fast-track could sell the clean energy attributes associated with the replacement generation to customers, providing an additional revenue stream to drive down the cost of the projects.

c. Allow Customers to Cover Incremental Upgrade Costs

Recognizing that there are and will continue to be some interconnection constraints, transparency about interconnection capacity will be essential. Developers serving customers considering participating in the customer programs will need to know where there is capacity to interconnect in order to site regulatory-surplus projects. The "red zones" are currently constrained for transmission-interconnected projects, and parts of the state may be constrained at the distribution level due to prior renewable development or other factors, but this does not foreclose the entire state at the transmission and distribution levels. Market actors with access to the necessary information about interconnection capacity

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[49] NV Energy Press Release: NV Energy's New Solar Projects to Replace Last Owned Coal Plant (Jan. 17, 2022), https://www.nvenergy.com/about-nvenergy/news/news-releases/nv-energys-new-solar-projects-to-replace-last-owned-coal-plant.

[50] Order Accepting Tariff Revisions, *Duke Energy Carolinas, LLC, Duke Energy Progress LLC, & Duke Energy Fla., LLC Duke Energy Progress, LLC Duke Energy Carolinas, LLC*, 180 FERC ¶ 61,156, P 7 (Sept. 6, 2022).

[51] *See Inflation Reduction Act of 2022*, U.S. Dep't of Energy, LPO, https://www.energy.gov/lpo/inflation-reduction-act-2022 (last visited Mar. 9, 2023).

[52] The White House, Building A Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action p.31, https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.

would be able to determine where and whether regulatory-surplus projects can be built.

The Arizona Public Service Company's (APS) Green Power Partners Program (GPPP) provides an example of how this capability can be built into a utility's customer program offerings.[53] The GPPP allows for three avenues of participation, the first two of which resemble the current options included by Duke in their GSAC proposal.[54] The third option, called "Green Commit" allows a customer to purchase "green power from a new APS resource, or group of resources, that is not part of the Company's planned resources or seeks to accelerate acquisition of a planned resource. (emphasis in original)"[55] To participate in Green Commit, the customer must cover "all incremental costs, including capital costs" and enter into an agreement for a fixed amount of green power from "the facility over a mutually agreeable term."[56]

The design of the GPPP's Green Commit option allows customers and sophisticated market actors to identify a suitable location for new renewable energy generation facilities beyond those already in APS's plans in order to serve their own clean energy supply needs—built at that customer's expense. The requirement that the clean power be "from a new APS resource, or group of resources...or seeks to accelerate acquisition of a planned resource" ensures the ability of the utility to smoothly integrate such a new facility into its operations, despite being in addition to original plans. The Green Commit option was recently successfully pursued by Microsoft Corporation, which agreed to purchase "RECs from 231 MW of wind energy capacity over a 20-year contract term" from a resource APS agreed to acquire "above and beyond the…planned capacity needed to serve all APS customers."[57]

d. Rely on Storage

In addition, there are creative ways to address interconnection constraints that do not require waiting for transmission or distribution grid upgrades. In locations where the grid is constrained only during limited peak periods, a new facility could use storage or even curtailment to guarantee that its exports would

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[53] *Green Power Partners Program*, APS, https://www.aps.com/en/Business/Service-Plans/Green-Power-Partners (last visited Apr. 20, 2023).
[54] The GPPP's "Green Connect" option is a subscription model similar to the GSAC's CEEA purchase option, while the GPPP's "Green Locate" option is a location specific model similar to the GSAC's three-party agreement option. *Id,*; Application, AZ. CORP. COMM'N, DOCKET NO. E-01345A-21-0203 (filed June 14, 2021), *available at* https://docket.images.azcc.gov/E000014011.pdf?i=1680293767194; Decision No. 78240, , AZ. CORP. COMM'N, DOCKET NO. E-01345A-21-0203 (filed Sept. 1, 2021), *available at* https://docket.images.azcc.gov/0000204610.pdf?i=1680292901890.
[55] *See supra* Application, AZ. CORP. COMM'N, DOCKET NO. E-01345A-21-0203, at 3.
[56] *Id.*
[57] Decision No. 78813, AZ. CORP. COMM'N, DOCKET NO. E-01345A-21-0203, at 2 (filed Dec. 15, 2022), *available at* https://docket.images.azcc.gov/0000208211.pdf?i=1680293767194.

be limited during peak periods and operate within grid constraints.[58] Transparency would again be essential; with timely, sufficient, and accurate information about grid constraints, market actors could determine whether a facility could be economically developed subject to operating limitations dictated by grid constraints.

e. Avoid Interconnection Constraints Through Small and Rooftop Facilities

There are a number of possibilities that avoid interconnection constraints altogether. Net energy metering projects as well as power-export Interconnection Customers such as Public Utility Regulatory Policies Act (PURPA) "qualifying facilities" (QFs) up to 250 kW are exempted from the DISIS process.[59] They are studied serially as received and Duke representatives have testified Duke has been successful connecting them on an expedited basis.[60] While successful development of these projects will still require transparency regarding interconnection capacity, projects within these thresholds should be very unlikely to encounter interconnection constraints and Duke should be able to continue connecting them on an expedited basis. These DISIS-exempt projects could be aggregated and the regulatory-surplus capacity offered in customer programs.

In most cases, the program design would rely on selling the clean-energy attributes (RECs plus carbon attributes) of the project to program participants in order to make the project affordable for a site-host participant. To avoid double-counting, only the program participant purchasing the clean-energy attributes would be able to claim the avoided carbon emissions associated with the project and the site-host participant would not, and this would need to be clear in marketing or educational materials and public communications. However, there likely are many potential site-host participants who would be more than happy with that arrangement in exchange for lower bills or additional revenue streams and the opportunity to help facilitate greater renewable energy deployment even if not formally taking credit for emissions reductions.

A program where participating customers purchase clean-energy attributes could facilitate deployment of a variety of small-scale renewable energy facilities. The program could use the sale of clean-energy attributes to support:

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[58] *See* Building a Technically Reliable Interconnection Evolution for Storage (BATRIES), Chapter III, Requirements for Limited- and Non-Export Controls, https://energystorageinterconnection.org/iii-requirements-for-limited-and-non-export-controls/ (last visited Mar. 15, 2023).

[59] Duke Queue Reform Reply Comments 30, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=f4bb5c1c-d832-441e-b307-4aba751ce75b; Duke Queue Reform Proposal 34, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=f83235af-6c15-4a08-ab04-7d03ef047383.

[60] Duke Queue Reform Update 7 (Oct. 15, 2019), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=f4bb5c1c-d832-441e-b307-4aba751ce75b.

- Small-scale (<250kW) community solar facilities, which could either be owned by Duke or sell under PURPA;
- Net-metered solar facilities hosted by non-residential customers, including local governments, up to 1MW, or 5MW if Duke's request to raise the cap is approved;
- Rooftop solar for low- and moderate-income homeowners, including on multi-family dwellings and affordable housing.

A program with these opportunities would not only procure new regulatory-surplus renewable energy, accelerating compliance with the 2030 carbon-reduction requirement, it could bring large ancillary economic benefits. It would make North Carolina's regulatory environment more appealing to commercial and industrial enterprises across the board; for those with ESG goals, it would make it feasible to procure regulatory-surplus renewable energy as program participants, and for those primarily concerned about reducing their electric bills it could offer a pathway to lower-cost net-metered solar. In addition, it could meaningfully contribute to reducing the energy burden of low- and moderate-income customers.

f. Summation

The suite of programs discussed above might be good candidates for piloting through Duke's forthcoming "rapid prototyping" proposal, pursuant to the Commission's final Carbon Plan order,[61] after further fleshing out with stakeholders. The Commission directed Duke to engage with stakeholders and develop guidelines for rapid prototyping precisely, as Duke proposed, in order to innovate more quickly in developing new customer programs.

8. Conclusion

Regulatory surplus is the essential feature of voluntary customer programs and the Commission should not approve any proposed programs that do not achieve it. Accordingly, the Commission should not approve the programs Duke has proposed to date, GSAC and CEI. The potential voluntary customer programs outlined above show that it is feasible to craft alternative voluntary customer programs that do achieve regulatory surplus. The Commission should direct Duke to work with stakeholders to quickly refine the potential voluntary customer programs outlined above or develop new programs that achieve regulatory

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[61] See Order Adopting Initial Carbon Plan and Providing Direction for Future Planning at 110, 134, Docket No. E-100, Sub 179, (N.C.U.C. December 30, 2022).

surplus. The resulting suite of programs might be good candidates for the forthcoming "rapid prototyping" process.

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ATTACHMENT 1

APPLYING THE CONSEQUENTIAL EMISSIONS FRAMEWORK FOR EMISSIONS-OPTIMIZED DECISION-MAKING FOR ENERGY PROCUREMENT AND MANAGEMENT

CEBI

Clean Energy Buyers Institute

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The accompanying ***Guide to Sourcing Marginal Emission Factor Data*** includes supplemental information about sources of marginal emissions factor data, the different methodologies used to estimate these factors, and a discussion of the strengths and limitations of these data.

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INTRODUCTION

Energy customers today are trying to integrate a wide array of next-generation considerations into their clean energy procurement decision-making: time-coincident matching with load, indirect avoided emissions impacts, land use and habitat impacts, life cycle environmental impacts, social justice and equity concerns, and local community engagement.[1] Although indirect avoided carbon emissions impact is just one of many metrics that an energy customer might consider, the Clean Energy Buyers Institute (CEBI) has witnessed a growing interest among energy customers in maximizing impact through this metric, in what many see as the decisive decade for swift climate action.

The two greenhouse gas (GHG) emissions accounting frameworks that exist today for a scope 2 inventory, or the indirect emissions from purchased electricity, heat, steam, or cooling, are the location-based and market-based frameworks. These frameworks apply an attributional emissions framework to attribute total power sector emissions to each user of the grid based on their electricity consumption and electricity and environmental attribute purchases. Although the attributional framework is an important tool for tracking emissions reductions and managing carbon budgets, it was neither designed nor intended to provide a perspective on the indirect consequence of a specific decision or project on avoided or future power sector emissions. The consequential emissions framework adds to the toolbox by providing insight into the future emissions impact of a specific project activity on power sector emissions, making it useful for impact-based decision-making.

This guide builds off of the learnings from CEBI's ***Next Generation Carbon-Free Electricity Procurement Activation Guide***, which shares the market evolvements needed to enable a broader suite of next-generation procurement options, such as procurement that maximizes the location- and time-based decarbonization potential of CFE procurement. This guide is also a continuation of CEBI's *Accelerating the Decarbonization Impact of Energy Procurement* primer and aims to help energy customers build an understanding of the effective application of the consequential emissions framework as a decision support tool (rather than its use for emissions offsets or avoided emissions claims). To help illustrate the framework in action, this paper traces an example of a clean energy procurement decision that a hypothetical company makes using the consequential emissions framework.

This paper strives to present a factual and practical discussion of the consequential emissions framework by synthesizing the most up-to-date guidance, research, knowledge, and perspectives on this topic. However, there is not yet an agreed-upon standard for applying this framework to decision-making, and through our months- long process of engaging with experts on this topic while writing this paper, we found that there is a need to continue alignment on this framework across the energy customer community as our collective understanding of the framework continues to evolve.

This paper was primarily written for participants in the U.S. voluntary clean energy market and has two intended audiences and purposes:

1. Organizational decision-makers — to help decide if and how to use consequential emissions impact as a metric to guide an organization's electricity sourcing or management strategies.
2. Organizational analysts — to help understand how to quantify consequential emissions impact and apply it to clean energy decision-making.

Defining the terminology

A wide variety of terms are used in connection to the consequential emissions framework: consequential emissions, avoided emissions, marginal emissions, displaced emissions, incremental emissions, and "emissionality." In this paper, we describe how the consequential emissions framework can support emissions-based decision-making through the use of marginal emissions factors to estimate the **consequential or marginal impact** of an action.

The consequential emissions framework seeks to establish and then quantify the causal relationship between an energy management or procurement decision and a change in indirect emissions from the power sector, relative to a counterfactual baseline in which the intervention did not occur. The broader consequential framework originated in the field of life cycle assessment as a method for quantifying how environmental impacts would change in response to an activity (in contrast to the attributional framework, which quantifies the environmental impact of the activity itself).

The avoided emissions impact is the metric optimized when making a procurement or energy management decision when using the consequential emissions framework. The goal is to maximize avoided indirect emissions (if a decision results in a reduction in consequential emissions), or to minimize induced indirect emissions (if a decision would increase consequential emissions). These emissions impacts are "indirect" because they occur at power plants that are generally neither owned nor controlled by the decision-maker. This impact can be quantified either through calculating the difference between modeled power sector emissions both with and without the intervention, or by using pre-calculated marginal emission factors.

Marginal emissions factors (MEFs), also referred to as marginal emissions rates, are the calculation factors that are most commonly used in the estimation of consequential emissions impact. They are called marginal factors because they generally describe the GHG emission rate (kilograms or pounds [lb] CO_2 per megawatt-hour [MWh]) of the marginal power generation source(s) that would change output or be built in response to a decision. This paper identifies four primary types of MEFs (operating, short-run, build, and long-run) that relate to different types of power system responses. Pre-calculated MEFs are more available and convenient for decision-making, so they are more commonly applied than custom marginal emissions modeling in the voluntary climate action context. Although MEFs are most commonly used for consequential analysis, in certain cases grid average emissions factors may reasonably approximate the consequential response of a power system to a decision.[2]

Avoided or induced emissions?

Different types of projects can either avoid or induce consequential emissions from the electrical grid:

In general, the types of project activities that may **avoid emissions** either generate electricity (like building a new solar farm) or reduce consumption of electricity (like energy efficiency or demand response).

In general, the types of project activities that may **induce emissions** are those that increase consumption of electricity (like electrification).

Certain project activities like energy storage and load shifting can either **avoid or induce emissions**.

However, the overall consequential impact also depends on considering the baseline emissions and direct emissions of the activity. For example, electrifying a vehicle fleet may induce indirect power sector emissions, but avoids direct emissions from the gas-powered vehicles being replaced. Or, for example, operating an on-site diesel generator avoids indirect power sector emissions, but induces direct diesel emissions from the on-site generator.

THE CONSEQUENTIAL EMISSIONS FRAMEWORK AS A DECISION SUPPORT TOOL

The consequential emissions framework generally seeks to establish and then quantify the causal relationship between an activity and an indirect change in emissions from the power sector, relative to a counterfactual baseline in which the intervention did not occur. This broader framework can be applied as either a decision support tool (which is covered in this paper) or as a method for making a unique, reportable claim to a specific volume of avoided emissions. For decision-making, the framework is used to compare the relative consequential emissions impacts of two or more options, rather than to quantify and convey ownership of the total global or direct emissions impact of a project activity, which is the focus of reporting and claims. The steps for applying the consequential framework in each context differ, so the steps presented in this paper for decision-making would not necessarily be appropriate for making a reportable claim to avoided emissions. Note that the indirect emissions impacts of an activity estimated during the decision-making phase are not likely to match the activity's actual indirect emissions impacts calculated retrospectively for claims or reporting, because of the differences in methodology, scope of analysis, and uncertainty about the future. The following table summarizes the key distinctions between these two applications of the consequential emissions framework.

APPLICATION OF THE CONSEQUENTIAL EMISSIONS FRAMEWORK:

	Decision-making	Claims/Reporting
Focus of this paper	Yes	No
Purpose/ motivation	Compare the relative impact of two or more options to choose the option that reduces indirect power sector emissions more rapidly than otherwise would happen	Quantify the indirect emissions impact of a single project activity to make a unique and accurate claim to indirect emissions reductions to reduce reported indirect emissions
Time frame	Typically future/prospective decisions	Typically retrospective analysis of an activity
Types of consequential emissions considered	Indirect grid emissions impact	Global emissions impact, including direct, life cycle emissions of the project activity itself and indirect (marginal) power sector emissions
Impact testing	Optional, but still important	Required
Monitoring/ verification	Unnecessary	Required
Existing standards/ guidance	None	*The GHG Protocol for Project Accounting* and *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects.*[3,4] *Making Credible Renewable Electricity Usage Claims.*[5]

Any user of the consequential emissions framework is essentially seeking to answer two questions: “Is my decision going to have an emissions impact?” and “If so, how much?” By asking these questions, decision-makers can make informed choices to understand indirect emissions impacts. However, the specific steps used to answer these two questions will differ depending on the use case. To use the consequential framework as a decision support tool, follow these steps:

01

Evaluate whether the activity will lead to new and permanent emissions reductions.

02

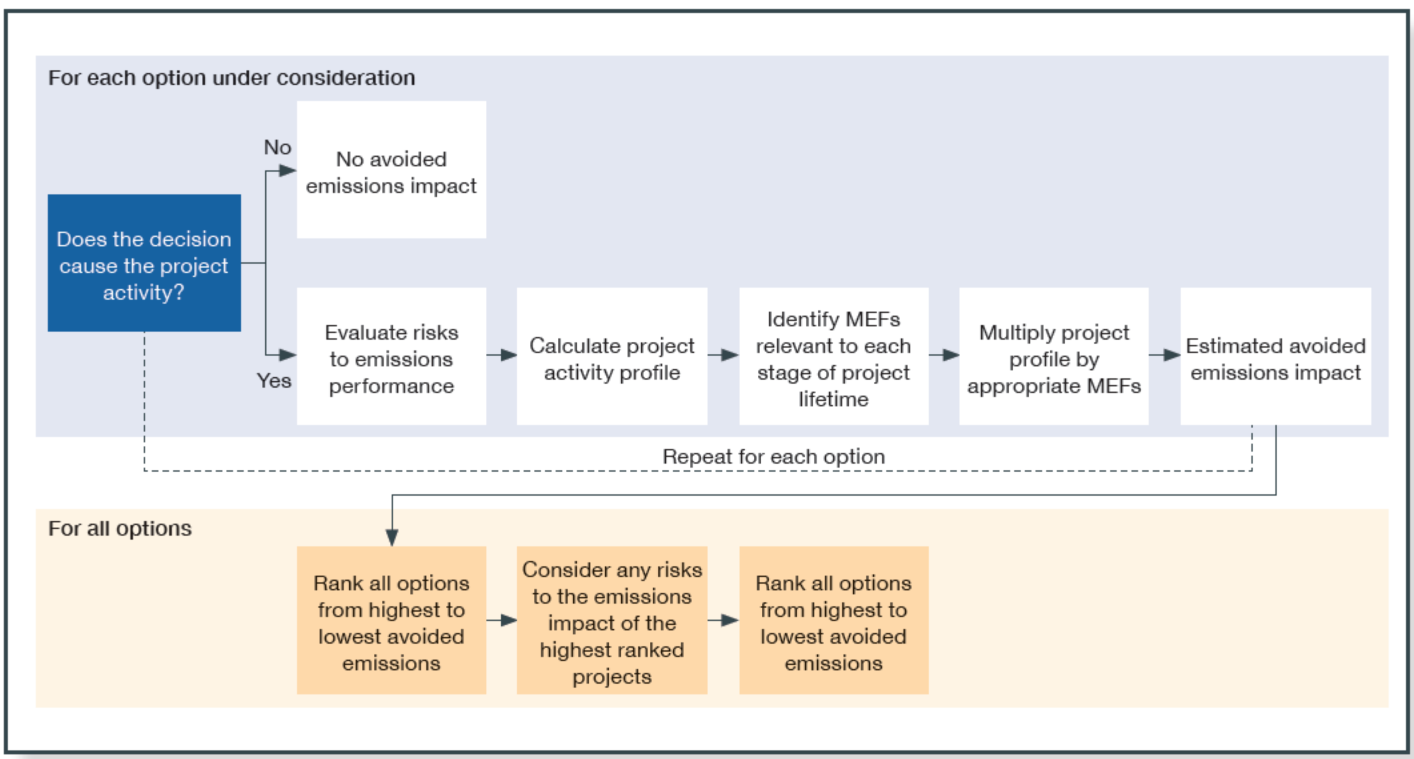
Estimate the incremental energy profile of the project activity.

03

Determine which types of MEFs are relevant to the project activity.

04

Calculate and compare the consequential, indirect emissions impact for each option.



STEP 1: Evaluate whether an activity will lead to indirect emission reductions that otherwise wouldn't have happened

Because the goal of using the consequential emissions framework for decision-making is to maximize a decision's indirect avoided emissions impact, first consider whether a decision will have any impact at all, or whether there are risk factors that could erode its avoided emissions impact. This step is the most subjective aspect of applying the consequential emissions framework, and each decision-maker may execute this step differently, depending on the rigor with which they want to ensure that their decision is causing new and meaningful indirect emissions reductions. Although the following considerations are not directly reflected in quantification of avoided emissions impact, if deciding between multiple options with a similar avoided emissions impact, these questions can help a decision-maker understand whether an option has a greater risk of not realizing the intended indirect emissions impacts.

Does my decision cause new, incremental indirect emissions reductions?

In the consequential framework, it is important to consider whether your decision causes the project activity that affects grid emissions. In general, a project activity is the actual project, program, or activity that affects a power system response, such as a new wind farm, energy efficiency measure, or electric vehicle (EV) charging. But a decision or an action is what causes the project activity to occur (for example, by signing a power purchase agreement, investing in an efficiency upgrade, or implementing a policy).

Often, this causal relationship is straightforward: Your decision to invest in a light-emitting diode (LED) lighting retrofit causes the LED retrofit to occur, and this retrofit reduces energy consumption. However, in other cases, especially regarding energy sourcing decisions, this causal relationship may not always exist. For example, a decision to procure clean energy from an existing generator generally does not directly cause more clean energy generation (the project activity), and thus will not lead to new emissions reductions (although sometimes it could be impactful to procure from an existing generator that would otherwise retire and be replaced by an emitting generator). So, for energy sourcing decisions, a simple way to evaluate this is to ask whether or not your decision will result in new clean energy generation.

Would these indirect emissions reductions have happened anyway?

When a decision-maker has limited resources (financial or otherwise) to take climate action, it is important to ensure that those resources are being used efficiently to maximize emissions impact. Thus, even when a decision causes new indirect emissions reductions, one should consider whether these emissions reductions might have happened anyway, whether or not the decision-maker spends their resources. For example, just because you sign a PPA for a new clean energy project doesn't necessarily mean that it wouldn't have been built anyway, especially if there are other energy customers in line who would be willing to sign the same contract. Although in practice these other buyers would likely then sign a different contract, resulting in a similar capacity of clean energy ultimately being built, if these other buyers are not considering emissions in their decisions, the alternate contracts they sign might not result in similar overall emissions impacts. While this is subjective, a decision-maker can ask whether their decision goes above and beyond what would have happened in common practice.

What is the risk that these indirect emissions reductions will not be permanent?

In certain cases, voluntary climate action can interact with climate regulations such as cap-and-trade programs or renewable portfolio standards in a way that can cancel out the intended power sector emissions reductions of the voluntary action.

When a project activity is located in a region with a cap-and-trade program, such as the Regional Greenhouse Gas Initiative, California's Cap and Trade Program, and the European Union Emissions Trading System, there is a risk that the indirect emissions reductions at the marginal generator caused by the activity may allow for increased emissions at other times or at other generators, resulting in no net emissions reductions in the long term. In cap-and-trade programs, a regulatory cap is set on total emissions, and emitters must buy and trade emissions allowances to cover all their emissions. When the emissions cap is binding, taking an action that reduces power sector emissions may free up emissions allowances that can be used to pollute at a later time or be sold to another emitter that allows them to emit more.[6–9] This risk can be mitigated by purchasing and retiring cap-and-trade allowances equivalent to the estimated emissions impact of a decision or reporting the activity as a voluntary set-aside in the cap-and-trade program (if such set-asides exist).[10]

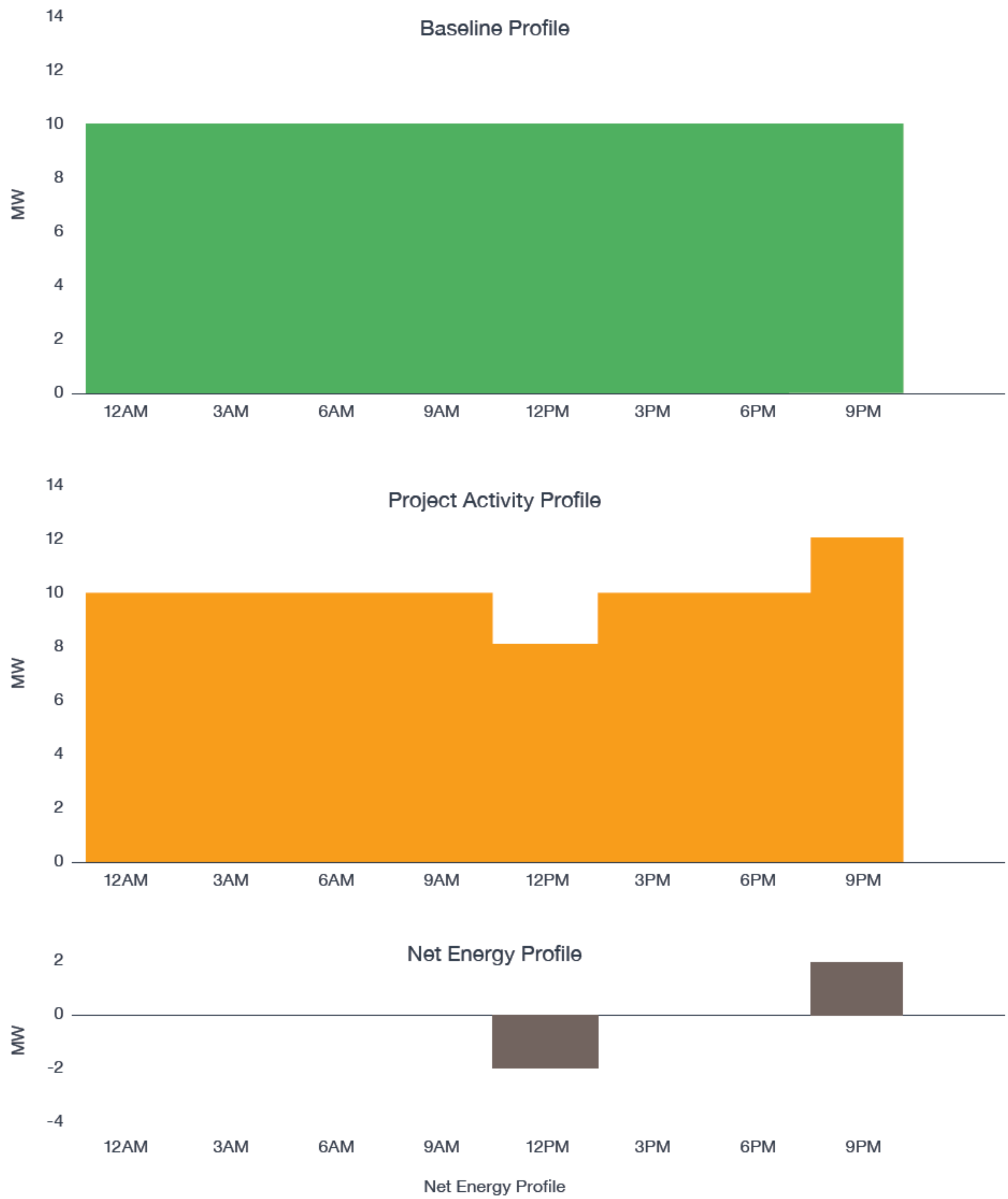
Another risk to the long-term avoided emissions impact of a new clean energy project occurs when an energy customer engages in renewable energy certificate (REC) swapping or REC arbitrage. When procuring clean energy located in a state with a renewable portfolio standard (RPS), the price of these "compliance-grade" RECs may be higher than RECs from voluntary markets because there are differences in eligible supply that can qualify for each market. Thus, some energy customers will sell their project's RECs for use in the local RPS and buy cheaper RECs from other (often existing) sources, arbitraging the value between the two types of RECs. However, if the RECs that were sold away are now used to help meet compliance with the RPS targets, this reduces the amount of clean energy that the local utility would have otherwise been mandated to procure. Engaging in this type of REC swap means that the voluntary clean energy procurement is no longer incremental to the amount of clean energy procurement that was mandated to happen anyway. To reduce this risk, energy customers would want to ensure that any compliance-grade RECs they sell are ultimately retired in a voluntary market, or avoid REC swapping altogether.

STEP 2: Estimate the net energy profile of the project activity

Calculating the indirect avoided emissions impact of an activity involves multiplying its net energy profile by the relevant MEFs. The marginal carbon intensity of the grid is constantly changing, and accurately estimating the indirect avoided emissions impact requires understanding of when a project activity affects the power sector operations, so that in each time period, its net energy profile can be multiplied by the appropriate MEF.

A net energy profile is generally represented by the hourly or sub-hourly energy generation or demand profile of an activity over its entire lifetime relative to (or net of) some baseline. For example, if the project activity is a new solar PV array, then the incremental energy profile would be represented by the estimated generation profile of the array over the 25 years of the project's lifetime. Or, if the decision pertains to when to shift load at a data center the next day, the net energy profile would be a single 24-hour period that represents the difference between the shifted load profile and the baseline load profile (see figure 1 for an example).

FIGURE 1. Over the course of a day, a data center consumes a flat 10 megawatts (MW) of electricity in all hours, representing the baseline profile. If the operator of this data center shifts some of its electricity demand from daytime to nighttime, the data center now consumes 8 MW from 12 PM to 3 PM, and 12 MW from 9 PM to midnight, with all other hours staying the same. This would represent the project activity profile. The net demand profile is the difference between the two, showing a 2 MW decrease from 12 PM to 3 PM and a 2 MW increase from 9 PM to midnight.



The overall length of this profile is an important characteristic when determining which MEFs are relevant to the project activity. In the data center example, if this were a temporary load-shifting decision that only applies to the next day, this net demand profile would be only one day long. If this were a permanent load-shaping decision that would be repeated every day for the next year, then the profile would be one year long, showing the repeating 24-hour net demand pattern every day of the year.

There may not be a single net energy profile for a project. To account for the uncertainty in the future generation or energy consumption of the project activity, it may make sense to calculate multiple net energy profiles so a range of potential impacts can be reflected in your analysis.

STEP 3: Determine which MEFs are relevant to the project activity

Once the project's net energy profile has been estimated, the next step involves determining what types of MEFs should be used to estimate the avoided emissions impact, based on how the power system is likely to respond to the specific type of activity. Although MEFs are commonly thought of as a single concept, there are actually many different types of MEFs that are relevant to different timescales or types of grid response. This paper identifies four primary types of MEFs: operating, short-run, build, and long-run. Before explaining how to choose the appropriate factor, it is first helpful to understand some background on how power systems respond to incremental changes in demand or generation.

Understanding marginal power system response

The dynamics of marginal emissions are understood through the science of power systems engineering and can be understood based on a few basic principles:

01	To maintain reliable delivery of electricity through a power grid, there must always be enough supply capacity available to meet demand.
02	This supply capacity must be dispatched to closely balance the electricity demand at all times.
03	Any project activity that disrupts this balance (whether in the short run or long run) generally requires a response from some part of the system to restore the equilibrium.

In power systems, the concept of "marginality" refers to the order in which power generators are dispatched to meet load. Generators are generally dispatched in order of lowest to highest cost, so the "marginal generators" are those with the highest cost needed to meet demand. In the simplest of terms, when demand decreases, the marginal generators will decrease output (and thus emissions), and if demand increases, the marginal generators will increase output (in some cases, however, decreasing demand can increase emissions, if power flow conditions require further rebalancing using a dirtier generator).[11]

Although the dynamics are slightly different, this concept plays out in both the short run and long run. In the short run, plugging in an EV increases demand, which requires certain generators to increase supply proportionally to maintain balance. The specific generators that respond to these actions change often and depend on factors such as the generator's marginal cost and operational characteristics, power flow over the transmission network, and the characteristics of the net demand profile. In the long run, adding new load, such as building a new data center in a region, may require the construction of a new power plant if there is not already enough capacity available to meet this future demand.

Multiple planning and operational processes, occurring over multiple timescales, work in concert to make sure that the grid always remains balanced. A project activity can affect the grid on multiple timescales and thus could have different marginal impacts over time. Understanding these timescales is important for selecting which type of marginal emission factor relates to a project activity. These timescales, from longest-term to shortest-term, are:[12]

Grid infrastructure decisions (Planning timescale — years ahead):
To ensure that there is enough generation capacity available to meet future electricity demand around the clock (and especially during peak demand times), grid planners must make decisions years in advance to build or retire capital assets on the grid, such as generators, energy storage, or transmission capacity. These decisions are based on long-term planning forecasts of anticipated demand, grid planning studies, and generator and load interconnection requests.

Generator commitment decisions (Scheduling timescale — hours to days ahead):
Because some generators take a long time to start up or shut down, grid operators will schedule or "commit" them to operate in certain hours the next day. In liberalized markets, these decisions are typically made as part of the day-ahead market. Commitment decisions are made based on a combination of short-term load forecasts, generator maintenance schedules, and supply offers and demand bids made by generators, load serving entities, and demand aggregators.

Generator dispatch decisions (Real-time timescale — minutes to hours ahead):
Decisions about the level at which each committed generator should be dispatched are typically made in real-time energy markets, minutes to hours ahead. These decisions are made based on short-run forecasts of demand and variable renewable generation and monitoring real-time grid conditions at the transmission level. Because changes in real-time market dispatch are typically not made more frequently than every five minutes, any grid response in the real-time market to an intervention would typically occur on a five-minute lag.

Automatic balancing and regulation (Instantaneous timescale — seconds or less ahead):
The final level of balancing is based on automated or physical processes that can respond on the order of seconds or less to any imbalances on the grid. For example, some generators have governors or automatic generator controls that respond to measured deviations in the electrical frequency of the grid. Other types of responses result from simple physics, such as the inertial response of a spinning generator. This type of balancing, which consists of regulation and frequency response services, represents the initial response of the grid to any intervention that affects the supply–demand balance.[13]

Understanding these different grid responses is important in the context of estimating indirect marginal emissions because generally different types of generators (which use different fuels and thus have different emission rates) will respond on different timescales.[13,14] As figure 2 illustrates, different types of resources were marginal in day-ahead and real-time energy markets in the California ISO in 2018. Even within ancillary services, different types of resources might provide "regulation up" (responding to an increase in demand) versus "regulation down" (responding to a decrease in demand).

FIGURE 2, part 1. In CAISO in 2018, the types of generators that were on the margin on the average day changed by time of day and depended on the grid planning timescale. The resources that provide instantaneous regulation up and down differ from the resources that are marginal in real-time markets and day-ahead markets.[15,16]

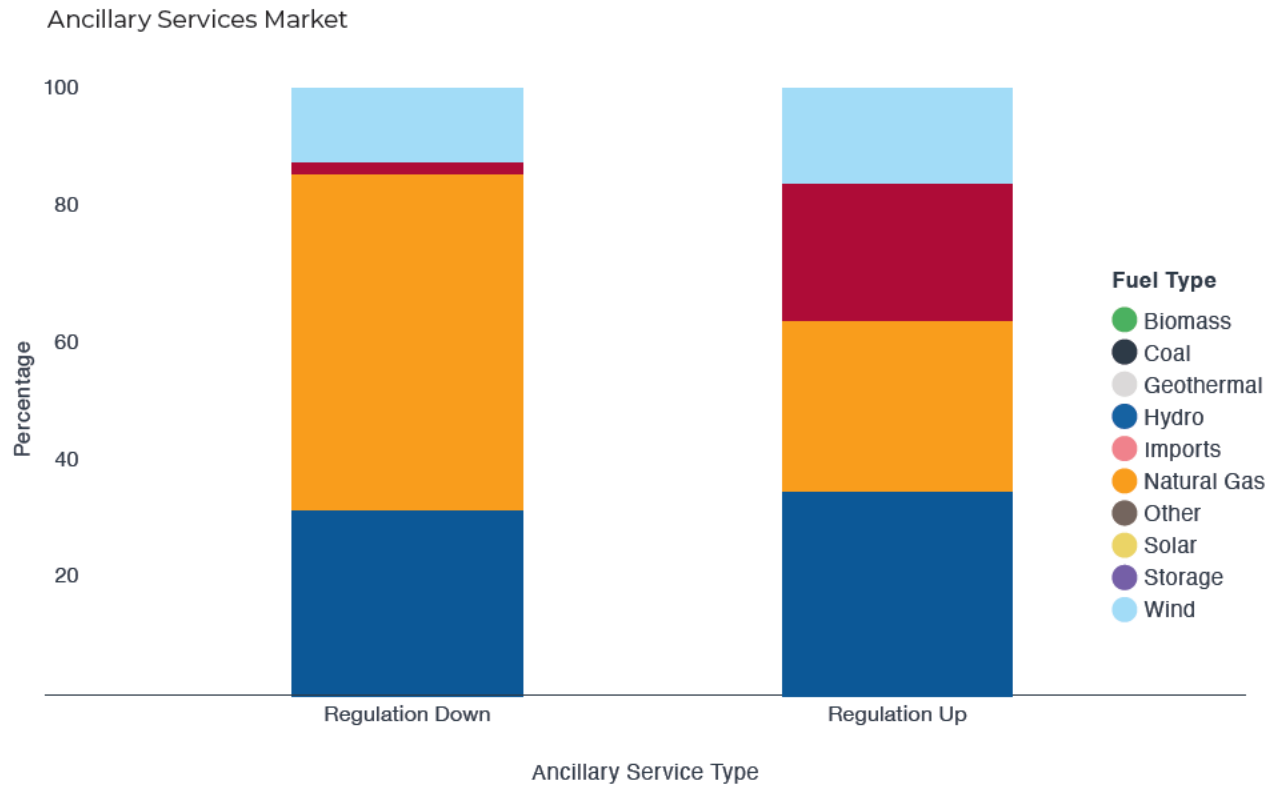


FIGURE 2, part 2

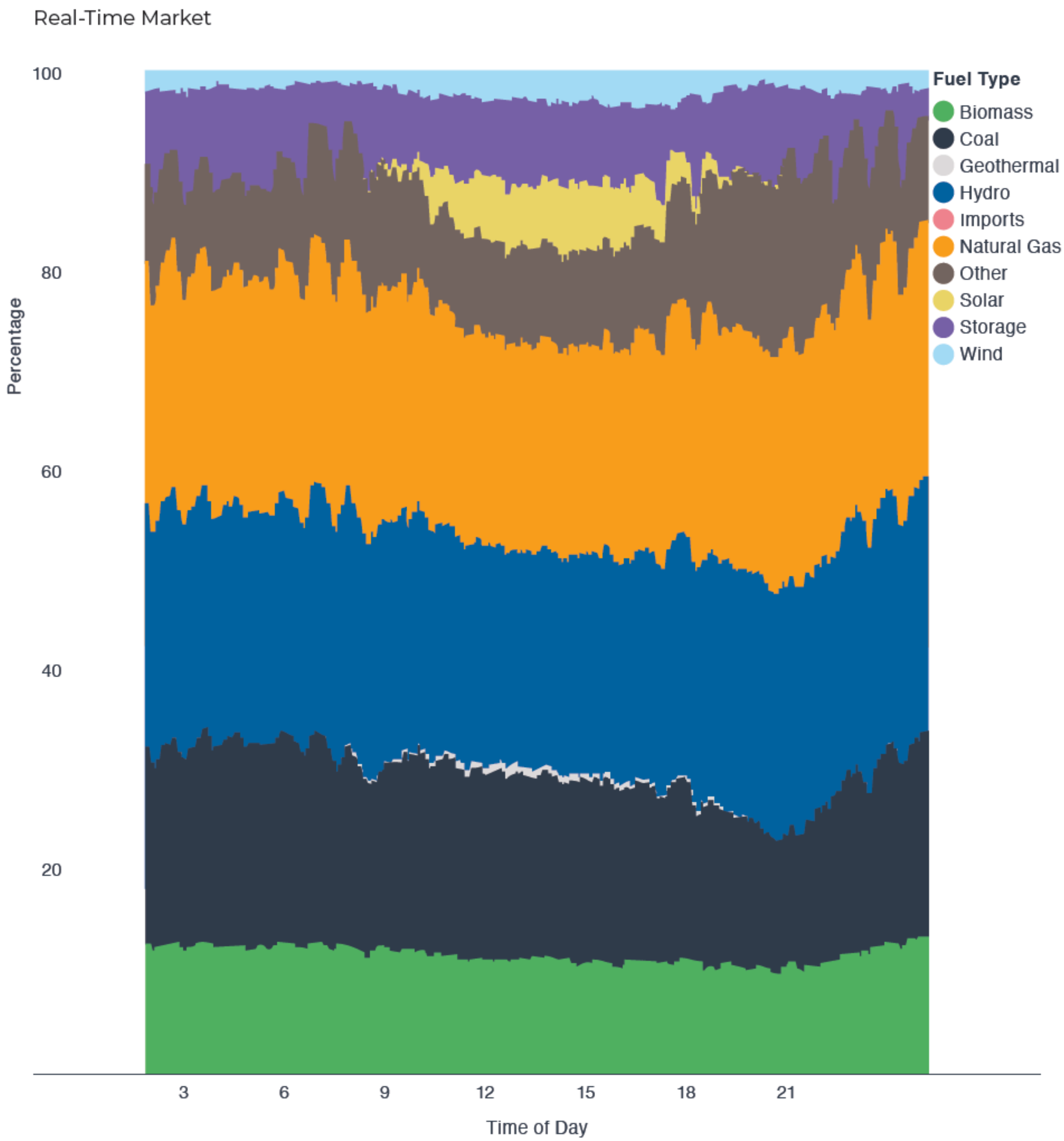
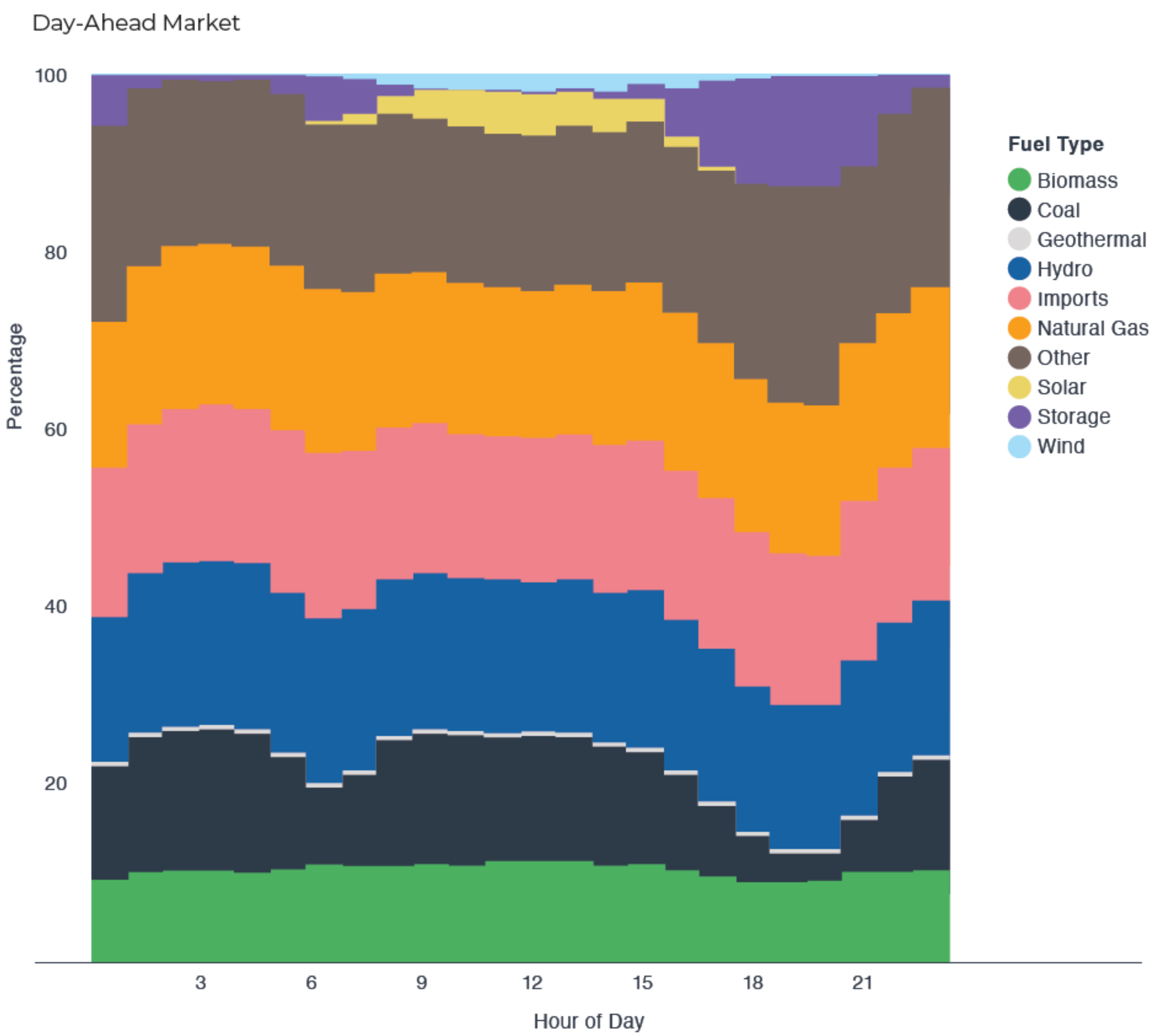


FIGURE 2, part 3



The four primary types of MEFs

This paper identifies four primary types of MEFs that correspond with different types of marginal power system response to an intervention.

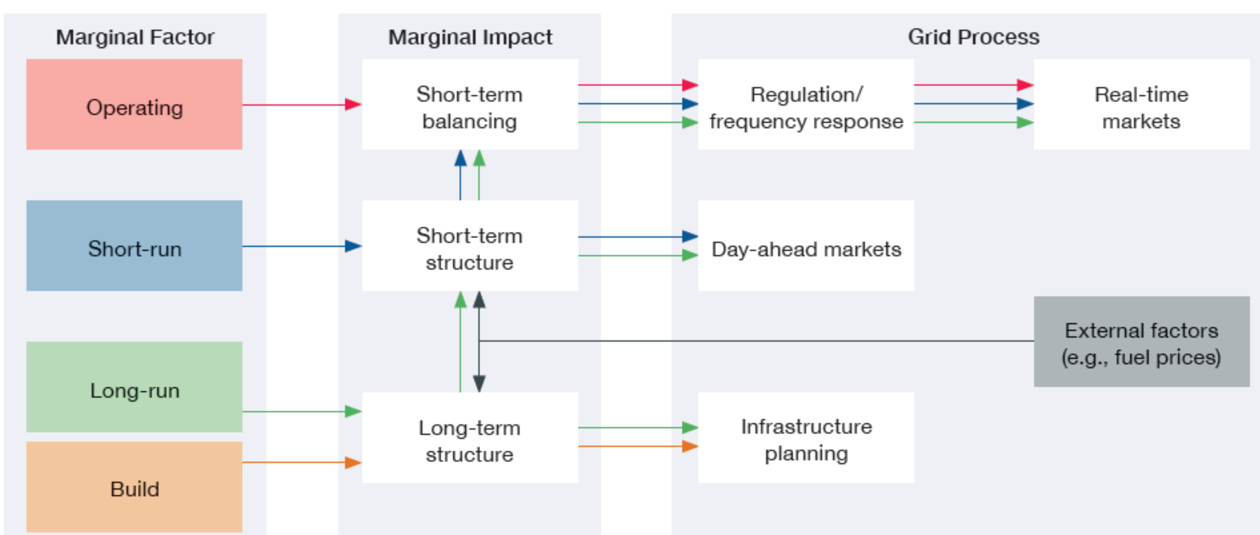
An **operating factor (OMEF)** describes the impact of an unpredictable intervention on the short-term balancing of the grid. Operating factors only describe the grid as it exists, literally, today: it assumes that generator commitment decisions and the fleet of generators itself are fixed.[4,17–19] This is why operating factors are often calculated dynamically and provided on a minute-by-minute or day-by-day basis for real-time optimization of energy use, rather than published ahead of time for use in estimating the lifetime impact of an intervention that might last for years.

A short-run factor (SRMEF) describes the impact of a more predictable intervention on the dispatch and commitment of existing generators (generally corresponding with real-time and day-ahead markets). Like the OMEF, the SRMEF describes the impact of an intervention on the operation of the grid, treating the generator fleet as mostly fixed, but, unlike the OMEF, it reflects limited systematic change (such as changing fuel prices or scheduling decisions).[17,20]

The build factor (BMEF) describes the average emission rate of the next generator that would be expected to be added to or retired from the current generation fleet in response to a consistent and predictable activity.[4,17,21] However, the build factor does not actually describe how the addition or retirement of that marginal generator impacts the operation of the grid, and the resulting emissions impact of that structural change. Thus, a BMEF may be a useful heuristic for decision-making (for example, answering “will shifting more load to midday help more solar get built?”), but it may be less useful for accurately quantifying the consequential emissions impact of a decision.

Finally, a long-run factor (LRMEF) describes the impact of a consistent and predictable intervention on both the structural evolution of the grid (that is, infrastructure addition and retirement decisions) and the impact of that structural evolution on the operation of the grid.[17,20] An important aspect of the long-run factor is that it assumes that the intervention actually causes the structural change (as opposed to short-run factors, which assume that any short-run structural changes result from external factors).[17,20] While long-run factors describe both structural and operational responses of the grid, they should not be thought of as a “combined” factor. The operating response reflected in a LRMEF describes the operating response only once the structural response has occurred. So, for example, if it takes five years for an activity to cause a structural grid response, the LRMEF would describe the emissions impact of the activity only after Year 5 — the first five years of the project activity would be reflected by a separate SRMEF.

FIGURE 3. This diagram shows the marginal impacts and grid processes that each type of marginal emission factor describes.



Determining the relevant MEFs for a project activity

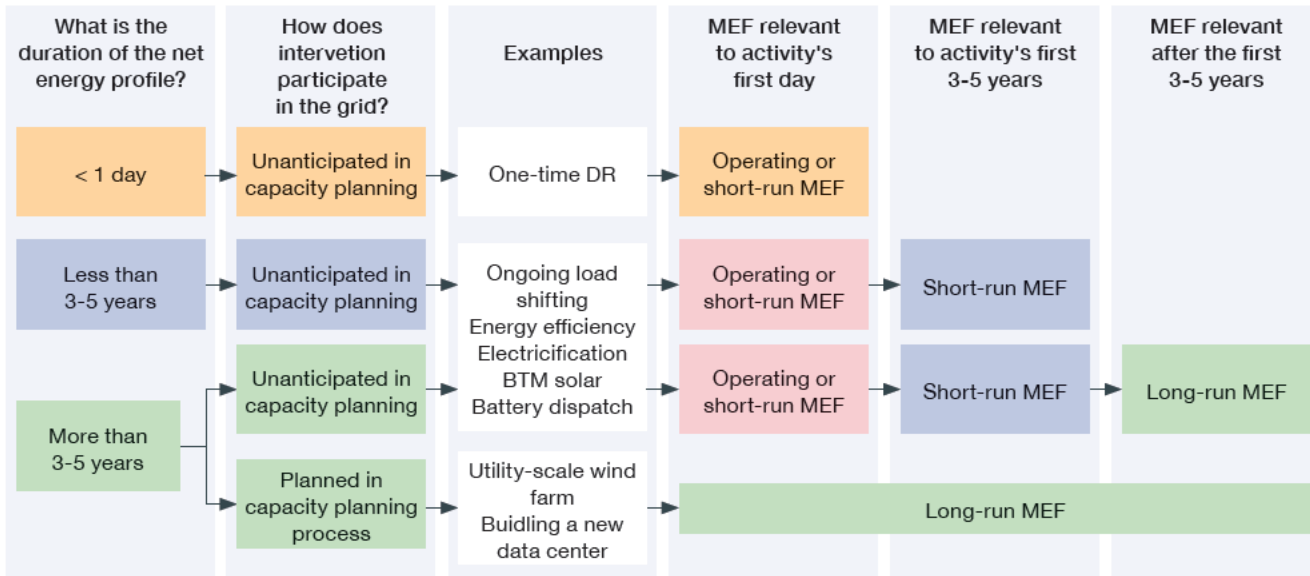
Because each type of factor represents emission impacts on different timescales, one or more of these factors could be used to estimate the impact of a single project activity over its entire lifespan. One can determine which factors are relevant to an activity by considering the duration of the activity's net energy profile and how the project activity formally participates in grid processes.

The duration of the net energy profile informs how permanent and predictable the project activity is and how the power system will respond to it. In general, a short-lived or transient decision will result in only an operating or short-run marginal response from the power system, while a long-lived decision or pattern of decisions can cause a long-run marginal response. Based on the various grid operation and planning timescales explained above, a general rule of thumb that can be used to determine the relevant MEF for each part of a decision's lifespan is: Operating MEFs best describe decisions lasting less than a day because they will only affect short-term grid balancing; short-run MEFs best describe decisions lasting less than several years; and long-run MEFs best describe the impacts lasting more than several years (generally more than three to five years) because this is how long it takes grid planning processes to effect structural change in response to an intervention.[21–23]

For long-lived decisions (those lasting more than three to five years), considering how the activity participates in formal electricity market or planning processes, and thus becomes known to grid operators and planners, is important to understand whether the activity will have an immediate or delayed long-run impact. Certain planned project activities, if they are large enough or connect directly to the transmission grid (like utility-scale generators or large industrial facilities), may participate in formal capacity planning processes years before being implemented, such as RTO planning studies or interconnection queues, and thus may result in structural change immediately upon commencement. The second category of non-participating project activities does not participate in any energy markets or planning processes, so grid operators only learn of these activities by detecting any imbalances they cause in real-time, or by observing changes in patterns that affect future forecasts of load or supply. For these project activities, there is generally a three- to five-year lag between when the activity commences and when the grid will structurally adapt to it. Thus, it would be appropriate to use a short-run factor for the first three to five years of a project activity, and then switch to a long-run factor for the remaining project life. Figure 4 illustrates how to select the appropriate MEF for each part of a project's lifetime.

There are certain cases when even a short-lived or dynamic decision, if part of a repeating pattern of ongoing short-lived decisions, may have the potential to effect some long-run structural change.[2] For example, the emissions impact of dynamically scheduling when an EV fleet charges each night after it is plugged in would be best described using an operating MEF. However, even though the specific charging times for the fleet change every day, if it is plugged in during the same time window every day, over time this could result in an average pattern of increased demand during those times, which could reasonably be described using a long-run MEF after the first three to five years. However, there is not yet an established method for how the relative operating and long-run impacts of such repeating, dynamic decisions should be weighed, or how the net energy profiles for each effect would be calculated.

FIGURE 4. This diagram illustrates how to determine which marginal emissions factors are relevant to different types of project activities and to which timescale each is relevant.



Identifying sources of MEF data

Once the appropriate types of MEFs have been identified, it will be necessary to identify a specific source of marginal emissions factor data to use in the analysis. There are many sources of marginal emissions factor data, each of which estimates these factors differently.

To aid readers in identifying and evaluating these different sources, the accompanying *Guide to Sourcing Marginal Emission Factor Data* will be helpful. The important takeaways from this guide are that each estimate of MEFs may differ from the others, and multiple sources should be used if possible; each MEF relates to a specific time period; all MEFs involve some uncertainty; and many pre-calculated MEFs are provided as “one size fits all” for all interventions, even if different types of interventions can cause different types of emissions impacts.

STEP 4: Calculate and compare the avoided emissions impact of each option

To estimate the avoided emissions impact of each option, one must first estimate the project activity’s net energy profile (Step 2) and identify the relevant MEFs by which each part of the net energy profile should be multiplied. It is important that when multiplied, the two multipliers are matched in both time and space. If you are considering different wind farms, one in Texas and one in New York, the Texas net generation profile should be multiplied by a MEF for the grid region or node where the wind farm is located in Texas, and likewise for the New York project. Similarly, the wind farm’s net generation in a specific hour should be multiplied by the MEF for that same hour (if time-specific factors are not available, use a factor that most closely matches when the activity is occurring).

It is important to use the relevant MEF for each part of the project's lifetime, which may require using multiple different types of MEFs for a single project activity. For example, if you are considering a commercial-scale rooftop solar array that may be unanticipated in grid planning processes, a short-run MEF would be multiplied by the first three to five years of the net generation profile, and a long-run MEF would be multiplied by the remaining net generation profile.

Hour of day	Net demand profile (MWh)	Operating MEF ($lbCO_2$/MWh)[24]	Emissions impact ($lbCO_2$)
1	0	466	0
2	0	660	0
3	0	932	0
4	0	932	0
5	0	932	0
6	0	932	0
7	0	932	0
8	0	932	0
9	0	932	0
10	0	932	0
11	0	932	0
12	0	932	0
13	–2	389	–778
14	–2	855	–1,710
15	–2	932	–1,864
16	0	932	0
17	0	932	0
18	0	932	0
19	0	932	0
20	0	466	0
21	0	466	0
22	2	855	1,710
23	2	696	1,392
24	2	460	920

Total Emissions Impact: –330

The total avoided emissions impact is the sum of the product of the net energy profile and MEFs for each time interval of the project's lifetime. The table on this page illustrates a simple example of this calculation for a potential load-shifting decision.

When starting these calculations, it is important to choose a sign convention and stick with it (in other words, whether a negative emissions impact represents a decrease or an increase in indirect emissions). Because this example shows a demand-side intervention, the result of –330 pounds (lb)CO_2 indicates that the decision would avoid 330 $lbCO_2$. However, were we examining a generation project, where net generation is represented as a positive number, avoided emissions would be shown as a positive number. If comparing supply-side and demand-side interventions side by side, it is important to use a consistent sign convention (for example, where generation is represented as negative demand, or demand is represented as negative generation), to avoid confusion about which options avoid indirect emissions and which might induce indirect emissions.

This is important because at certain times the marginal emission factor could be negative (meaning that a reduction in demand actually leads to an increase in emissions, or vice versa). For example, because of re-dispatch of generators required to respond to constraints on power flow, a reduction in energy demand may cause a relatively cleaner natural gas plant to reduce output, but require a dirtier coal plant to increase output, leading to a net increase in emissions.[25]

Finally, when estimating indirect avoided emissions impacts, one should consider the effect of uncertainty. This means that the calculated emissions impact of each option should never be a single number, but rather a range of estimates that should reflect any uncertainties in the net energy profile or the marginal emissions factor itself (although data providers do not always publish uncertainty ranges for their estimates).

Depending on the context of the decision-making process, it may help to consider normalized emissions impact metrics in addition to, or instead of, total avoided emissions. For example, if the decision-maker has a set budget for all of their climate action programs, and the options under consideration cost different amounts, they may wish to maximize the indirect avoided emissions impact per dollar spent. Or, if a decision-maker is trying to achieve an energy procurement goal that requires the company to buy a certain volume of total energy, they may wish to maximize the avoided emissions per MWh generated by each project.

EMISSIONS-BASED RENEWABLE ENERGY PROCUREMENT EXAMPLE

To demonstrate the consequential emissions framework in action, below is a hypothetical example of a U.S. company seeking to maximize the avoided emissions impact from the electricity it procures to meet its 100% clean energy goal. In 2022, the company issues a request for proposals for 100 MW of clean energy capacity anywhere in the United States. They receive offers for virtual power purchase agreements to buy both the energy and RECs from these eight projects:

Capacity	Technology	Location	Commercial operation date
100 MW	Solar	Southern California	2024 (New build)
100 MW	Solar	New York	2024 (New build)
100 MW	Solar	South Dakota	2024 (New build)
100 MW	Solar	Louisiana	2024 (New build)
100 MW	Wind	Western Pennsylvania	2024 (New build)
100 MW	Wind	Illinois	2024 (New build)
100 MW	Wind	Oregon	2024 (New build)
100 MW	Wind	West Texas	2018 (Existing merchant plant)

The company's energy manager asks her energy analyst to evaluate which project the company should contract with to maximize the avoided emissions impact of its procurement.

STEP 1 IN ACTION: Evaluating potential risks to the emissions impact of each project

As a first step, the analyst considers whether each project will lead to new emissions reductions that wouldn't have otherwise happened, and whether there is any risk that the emissions reductions would not be permanent or incremental. Note that because this step can be subjective, and because this is meant to be illustrative, readers should not interpret this hypothetical analyst's judgments as generalizable conclusions.

The analyst first considers whether each project will lead to new, incremental emissions reductions by examining whether each project represents new clean energy generation. Because most projects have a future operational date and have not yet been built, she judges that these projects would cause new emissions reductions. However, the West Texas wind offer comes from an existing merchant generator that began operation in 2018. While this project would have started displacing grid emissions when it was first built, their company's emissions-based procurement goal is to effect new emissions reductions, so she removes this project from consideration.

Next, she evaluates whether there is a risk that each project would be built anyway, even if the company didn't choose that project. To evaluate this, she looks at voluntary clean energy market conditions and grid interconnection queues in each region to better understand whether each resource is being built as a matter of common practice. Although this is subjective, she is trying to determine where a project would likely not be built if the company didn't sign the contract.

Finally, she considers the risk that any indirect emissions reductions would not be permanent because there may be interactions with regulatory programs in the regions where each project is located. To do so, she evaluates whether each project is located in a region with cap and trade or with an active renewable portfolio standard.

After completing this step, she develops the following table to help her energy manager understand the potential emissions impact risks of each project:

Example evaluation of risk factors for the projects being considered by the analyst. Note: This is an illustrative example based on a hypothetical analyst's subjective judgment, and these risk factors should not be interpreted as generalizable for similar real-world projects.

PROJECT	NEW EMISSIONS REDUCTIONS	LIKELIHOOD OF BEING BUILT ANYWAY	RISK TO IMPACT FROM CAP AND TRADE	RISK TO IMPACT RECS SWAPPED (PROJECT IN STATE WITH ACTIVE RPS)	OVERALL RISK TO EMISSIONS IMPACT
CA Solar	Yes	High	Yes	Yes	High
NY Solar	Yes	Med	Yes	Yes	Med-High
SD Solar	Yes	Low	No	No	Low
LA Solar	Yes	Low	No	No	Low
PA Wind	Yes	Med	No	No	Med-Low
IL Wind	Yes	Low	No	Yes	Med
OR Wind	Yes	Med	Yes	Yes	Med-High
TX Wind	No	High	No	No	High

STEP 2 IN ACTION: Estimating the net generation profiles for each project activity

Because renewable generation varies by time of day and season, the analyst will need to use hourly time series data that represent this variability to calculate net generation profiles. Estimating the exact generation patterns over the 25-year lifespans of each project would be difficult, so the analyst represents each year of the project activity using historical wind and solar resource data from eight different years (2007–2014), which will help represent the uncertainty in generation patterns due to weather. To estimate generation profiles for each of the four projects, the analyst uses the National Renewable Energy Laboratory's (NREL) System Advisor Model software to simulate this generation for each resource year (although she could ask the project developers for these different profiles).

For the seven new projects, the net energy profile represents the estimated generation from each project. Because the Texas wind project is existing and not at risk of shutting down, the baseline generation profile is the same as the project activity profile, so the net generation profile is zero (meaning a decision to procure energy from this project will have zero consequential emissions impact).

STEP 3 IN ACTION: Determining the relevant MEFs

Because all of these projects are utility-scale wind and solar projects, the analyst determines that using a LRMEF would be appropriate to use for the entire lifetime of the project, because these projects would likely participate in local capacity planning processes and effect structural change from day one. However, to reflect any potential uncertainty that this structural change would not happen right away (and because this is an illustrative example), she chooses to calculate the marginal emissions impact of the first five years of each project activity not only using a LRMEF, but also using SRMEFs. For LRMEFs, she uses data from NREL's Cambium model. Cambium provides LRMEFs for five different future scenarios (Mid Case, Low Renewable Energy Cost, High Renewable Energy Cost, Grid Decarbonization by 2050, and Grid Decarbonization by 2035), so she uses all five of these to reflect how uncertainty about the future might affect her analysis. For short-run factors, she uses the same five scenarios for the SRMEF data provided by Cambium, as well as the project-specific MEFs from AVERT and the non-baseload MEFs from eGRID. By using factors from multiple different sources, she can reflect how uncertainty in different types of MEF estimates might affect her analysis. By incorporating three different sources of uncertainty (from clean energy generation patterns, different MEF estimation methodologies, and uncertainty about the future), and comparing whether they all lead to the same decision outcome, she can better understand the certainty that the project she recommends will, indeed, lead to the greatest amount of indirect avoided emissions. For this illustrative example, these specific MEFs were chosen because they are free and publicly available.

STEP 4 IN ACTION: Calculating and comparing the options

Now that the analyst has estimated the net generation profiles for each project and collected the relevant MEFs she will use for each project, it is time to calculate the range of possible indirect avoided emissions impacts. For the first five years of each project lifetime, she will multiply the net generation profile of each project by 12 different MEFs: five different scenarios for the Cambium LRMEF, five different scenarios for the Cambium SRMEF, the AVERT SRMEF, and the eGRID SRMEF. For the final 20 years of each project's 25-year lifespan, she will multiply the net generation profiles by the five different LRMEFs representing each Cambium scenario. She will then add the impact from the first five years to the impact from the final 20 years to arrive at the range of total avoided emissions impacts for each project.

The figure on the following page shows the results of these calculations for the first five years of the project life, the final 20 years of the project life, and the range of total estimated indirect avoided emissions over the entire life of the project. The analyst notes that the Pennsylvania wind project appears to be the most likely project to avoid the greatest amount of emissions. Consulting her risk table that she developed during Step 1, she sees that this project has relatively low emissions impact risk. Thus, she feels confident recommending this project from an emissions-based procurement standpoint.

However, her energy manager comes back to her a week later to tell her they have determined that the Pennsylvania and Illinois wind projects are not financially viable for the company to procure from, and asks her to recommend a different project. Her analysis shows that the next best two projects are the Oregon wind and Louisiana solar projects, although there is not a significant difference between the range of estimated avoided emissions impacts for the two projects. In situations like this, the analyst's risk evaluation might play a larger role: She notes that several factors cause her to judge that there is a medium-high risk that the indirect emissions impacts of the Oregon wind project could be eroded. Thus, she decides to recommend the Louisiana solar project, because it has a low risk.

This example demonstrates why it is important to consider multiple MEF estimates: The relative rank ordering of each project will not always be the same, so relying on a single source of MEF data might result in a different decision than if multiple sources were considered together. In this example, because the Pennsylvania wind project had the highest capacity factor (and thus the greatest amount of generation) of the projects, it consistently ranked as the best project across all MEF scenarios. If the analyst were considering projects that generated roughly the same amount of electricity, or using a metric normalized by the number of megawatt-hours, the highest-ranked project might not always be consistent. In such cases, it may be necessary to consider weighting the different estimates based on a subjective estimate of their relative quality (the accompanying MEF sourcing guide includes several factors that may be considered to help judge quality).

FIGURE 5. Avoided Emissions Impact for Each Project's First Five Years of Operation (2024–2028)

These figures show the range of total avoided emissions for the first five years (top), last 20 years (middle), and entire lifetime (bottom) for each project being considered. Depending on the marginal emissions factor used, the total magnitude of avoided emissions can range significantly. Each box plot in the bottom panel represents 480 different scenarios for each project (8 resource years x 12 MEFs for the first five years and x 5 MEFs for the final 20 years).

CONCLUSION

The consequential emissions framework is an important decision support tool for guiding a range of decarbonization decisions, from energy efficiency and clean energy procurement to real-time battery charging and demand response decisions. Analyzing the marginal emissions impact of decisions can help provide a well-rounded perspective on an organization's climate impact, alongside its GHG inventory.

For those who are ready to take the next step in applying this framework to support their decision-making, the accompanying *Guide to Sourcing Marginal Emission Factor Data* is intended as a resource to help energy customers identify specific sources of marginal emissions factor data and provide additional background about how these factors are calculated.

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Thank You!

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ATTACHMENT 2

- **General Understanding for Duke Energy owned facilities**
- Duke Energy will retain the rights to the Carbon Emissions Attributes
  - Required to be able to have the generation count towards carbon reduction
- Renewable Energy Attributes (RECs) can be sold to customers
  - RECs will be priced at fair market value
  - Money received will help “buy down” the cost of our projects/benefits all customers
  - RECs will be retired by Duke Energy on the Customer’s behalf